STATE OF NEW JERSEY

Board of Public Utilities
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ENERGY

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY D/B/A CONECTIV POWER DELIVERY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES FOR ELECTRIC SERVICE	**))))))**	**FINAL DECISION AND ORDER** **BPU Dkt. No. ER02080510** **OAL Dkt. No. PUC 6917-02**

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Final Decision and Order memorializes and provides the reasoning for the action taken by the Board of Public Utilities ("Board" or "BPU") in the above captioned matter by a vote of five Commissioners at the Board's July 21, 2003 public meeting, which action was summarized in the Board's Summary Order dated July 31, 2003. This Final Decision and Order supersedes the Board's July 31, 2003 Summary Order.

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I. BACKGROUND

This matter concerns a petition filed with the Board of Public Utilities ("Board" or "BPU") on August 1, 2002, by Atlantic City Electric Company d/b/a Conectiv Power Delivery ("ACE" "Atlantic" or "Company"), requesting an increase in rates for electric service pursuant to N.J.S.A. 48:2-21 and N.J.A.C. 14:1-5.12 ("Petition" or "deferred balances case"). The Petition was filed pursuant to the Board's directive at pages 73-74 of its March 30, 2001 Final Decision and Order in Docket Nos. EO97070455, EO97070456 and EO97070457*, In the Matter of Atlantic City Electric Company – Rate Unbundling, Stranded Cost and Restructuring Filings* ("Final Restructuring Order"), and requested the Board's approval to reset the Company's Market Transition Charge ("MTC"), Net Non-Utility Generation Charge ("NNC") and Societal Benefits Charge ("SBC") effective August 1, 2003, thereby beginning recovery of its deferred balances incurred in billing the level of these charges previously in effect. If approved by the Board as filed, the net effect of the proposed rate changes would be to increase ACE's annual revenue by $71.6 million, of which $43.4 million would be applied to the recovery of the deferred balances, representing an increase in overall rates of approximately 8.4%.

This Order does not address ACE's petition for an increase in its base rates, *I/M/O the Petition of Atlantic City Electric Company d/b/a/ Conectiv Power Delivery for Approval of Amendments to its Tariff to Provide for an Increase in Rates for Electric Service*, BPU Dkt. No. ER03020110 ("base rate case"), which was filed on February 1, 2003, and remains pending at the Office of Administrative Law ("OAL").

ACE is engaged in the transmission, distribution and sale of electric energy to approximately 505,000 residential, commercial, and industrial customers in the southern portion of the State. Before considering the record that has been developed in this matter, a brief description of the events leading to this filing is provided below.

On February 9, 1999, the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 *et seq.* ("EDECA") was enacted. EDECA required the Board by Order to provide that, by no later than August 1, 1999, each of the State's electric utilities to simultaneously: open 100% of their franchised service areas to retail generation competition, N.J.S.A. 48:3-53.a.; reduce their aggregate level of rates for each customer class by no less than five percent, N.J.S.A. 48:3-52.d.(2), with an additional 5% reduction to be implemented no later than August 1, 2002; unbundle their rate schedules into discrete services and charges, N.J.S.A. 48:3-52.a.; provide basic generation service ("BGS") at approved rates for customers who do not choose an alternate power supplier, N.J.S.A. 48:3-57; provide approved "shopping credits" to be deducted from the bills of customers who choose an alternate power supplier, N.J.S.A. 48:3-52.b.; implement a Societal Benefits Charge to recover the cost of previously approved social, environmental and demand side management ("DSM") programs included in the utilities' bundled rates, N.J.S.A. 48:3-60.a.; and implement a Market Transition Charge to allow each utility the opportunity to recover an approved level of stranded costs resulting from restructuring, as determined by the Board, N.J.S.A. 48:3-61.

Prior to the enactment of EDECA, the movement toward energy market competition was already underway. The New Jersey Energy Master Plan Phase I Report, released in March 1995, presented a vision for the State in which energy markets would be guided by market-based principles and competition. Thereafter, after conducting extensive proceedings, on April 30, 1997, the Board issued an Order adopting and releasing a report entitled *Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations*, BPU Docket No. EX94120585Y, dated April 30, 1997 ("Final Report," also referred to as the "Green Book"). The Final Report was submitted to the Governor and the Legislature for their consideration. In anticipation of the enactment of restructuring legislation, the Board's April 30, 1997 Order directed each of the State's four investor owned electric utilities to make three filings by July 15, 1997: a rate unbundling petition, a stranded costs petition, and a restructuring plan.

On July 15, 1997, ACE filed verified petitions with the BPU setting forth its unbundling, stranded costs and restructuring proposals. The unbundling and stranded costs petitions were assigned BPU Docket Nos. EO97070455 and EO97070456, respectively, and were transmitted to the OAL and assigned to Administrative Law Judge ("ALJ") William Gural. The restructuring petition was assigned BPU Docket No. EO97070457, and was retained by the Board. After extensive hearings and briefing, ALJ Gural issued an Initial Decision on the unbundling and stranded costs issues in August 1998. Hearings on all four utilities' restructuring petitions were held before the Board and chaired by Commissioner Carmen J. Armenti in April and May 1998.

On February 11, 1999, shortly after the enactment of EDECA, the BPU established guidelines and a schedule for the commencement of settlement negotiations among the parties in ACE's restructuring proceedings. Though all parties could not reach a comprehensive settlement, two proposed stipulations of settlement were filed with the BPU in June 1999. One proposed settlement ("Stipulation I") was executed by ACE and four other parties. An alternative settlement ("Stipulation II") was executed by the Division of the Ratepayer Advocate ("RPA" or "Advocate") and three other parties. After reviewing the evidentiary record, including the proposed settlements and comments of the parties, as well as the requirements of EDECA, on July 15, 1999, the Board issued a Summary Order in the three restructuring dockets, *I/M/O Atlantic City Electric Company – Rate Unbundling, Stranded Costs and Restructuring Filings,* Docket Nos. EO97070455, EO97070456 and EO97070457 ("Summary Restructuring Order"), followed by the issuance of a Final Restructuring Order on March 30, 2001.

In its Summary and Final Restructuring Orders (collectively "Restructuring Orders"), the BPU modified the ALJ's Initial Decision in light of subsequent developments, finding that the elements of Stipulation I, with certain modifications and clarifications to address concerns raised by the parties, provided an appropriate framework for a reasonable resolution to the unbundling, stranded costs and restructuring filings. Pursuant to EDECA, the BPU designated a four-year "Transition Period" starting August 1, 1999, during which Board-approved unbundled rates would be in effect. The Board also directed ACE to implement rate reductions over the Transition Period, including a 5% reduction effective August 1, 1999, an additional 2% reduction no later than January 1, 2001, and a further 3.2% reduction on August 1, 2002 for a total aggregate reduction of 10.2% effective on that date, which was to be sustained until July 31, 2003.[1]

Consistent with EDECA, the Board found that ACE was entitled to recover its reasonable and prudently incurred BGS costs, its reasonable and prudently incurred restructuring related costs (via the MTC), its above-market non-utility generation ("NUG") costs (via the NNC), and the approved costs of its social, environmental, DSM and consumer education programs (via the SBC). The Board further found that, to the extent ACE might have to defer recovery of some portion of such costs in order to achieve or sustain rate reductions during the Transition Period, those costs could be deferred, but would be subject to a prudence review and audit by the Board prior to commencing recovery at the end of the Transition Period. The Board also authorized the accrual of interest on the unamortized balances of all deferrals at the yield on constant-maturity seven-year treasury notes plus 60 basis points, as reported in the Federal Reserve Statistical Release issued closest to August 1st of each year of the Transition Period.

The Final Restructuring Order also required ACE to file a petition no later than August 1, 2002, proposing the level of the NNC, MTC and SBC unbundled rate components that would go into effect on August 1, 2003, for the Board's consideration prior to the end of the Transition Period.

To assist the Board in its review of the deferred balances, on July 29, 2002, the Board issued a Request for Proposals ("RFP") to secure the services of an independent accountant, auditor or consultant to conduct audits of the restructuring-related deferred balances of New Jersey's four electric utilities. The Board's objective was to obtain certified opinions as to whether the utilities' deferred balances were correct and included only those costs that were reasonable, prudently incurred, accurately calculated, correctly recorded and in compliance with all applicable Board Orders. Regarding prudence of BGS costs, the Auditors were directed to offer an opinion as to whether the utilities pursued a prudent procurement procedure for the acquisition of BGS supply and whether, when required, they purchased power at reasonable prices consistent with market conditions in the competitive wholesale marketplace and consistent with appropriate hedging techniques. The Auditors were also directed to comment on the utilities' efforts to mitigate above-market NUG contract costs during the Transition Period. The audit was to be completed in two phases: the first covering the first three years of the Transition Period, ending July 31, 2002, and the second covering the final year of the Transition Period, ending July 31, 2003. On October 2, 2002, the Board selected Mitchell & Titus, LLP ("M&T") and Barrington-Wellesley Group, Inc. ("BWG") (collectively, "Auditors") to perform the audit of ACE's deferred balances.

On July 31, 2002, Governor McGreevey convened, by Executive Order 25, a Deferred Balances Task Force to examine "the reasons why the deferred balances were accumulated, what mitigation steps utilities took to reduce deferred balances and how they ought to be addressed to best protect the interest of ratepayers, including an evaluation of the merits of securitizing deferred balances." In its report issued on August 30, 2002, the Task Force recommended that

[1] As a result of buying out its power purchase agreement ("PPA") with the Pedricktown NUG, in accordance with the Restructuring Orders the Company implemented a 1% rate reduction on January 1, 2000, followed by a further 1% reduction on January 1, 2001, to implement the 2% reduction on that date.

full evidentiary hearings be held and an independent audit be preformed to ensure that the burden of proof for recovering the deferred balances was placed squarely on the utility companies. Also as recommended by the report, on September 6, 2002, the Governor signed into law Senate Bill 869, containing certain modifications to EDECA which would allow, but not require, the BPU to permit securitization of "Basic Generation Service Transition Costs," as defined therein. N.J.S.A. 48:3-51 and -62.

II. PROCEDURAL HISTORY

As noted above, on August 1, 2002, ACE filed its deferred balances case, proposing that the MTC, NNC and SBC rate components be reset for the period from August 1, 2003 through May 31, 2004, and be subject to continued deferred accounting beyond the end of the Transition Period. ACE further proposed that the unbundled rates be reset annually and be subject to "true-up" based on the costs incurred and recovered in the previous billing period. The ten-month initial billing period was proposed on the expectation the Company's unbundled rates would next be reset on June 1, 2004, and then on each June 1 thereafter, thus allowing future rate changes to coincide with both the Company's already existing summer/winter rate changes and the changes in BGS rates implemented on June 1 pursuant to the statewide auction conducted to obtain BGS supply for the State's electric utilities.

As filed, the Petition sought annual increases of $32.6 million in the MTC, $40.1 million in the NNC, and a decrease of $1.1 million in the SBC, for a total net increase of $71.6 million, or 8.4%. (Petition at 4). ACE estimated that its aggregate deferred balance (the combined BGS, MTC, NNC and SBC balances) would be approximately $176.4 million, including interest, as of July 31, 2003, the end of the Transition Period. This amount was net of a $30.5 million write off taken in August 2002 in accordance with the settlement of the proceedings before the Board in which the Company sought approval of its parent company's merger agreement with Pepco Holdings, Inc., which was granted by Board Order in Docket No. EM 01050308, dated July 3, 2002.

The Company proposed recovering its aggregate deferred balance over a four-year period, with interest to be accrued on the unamortized balance at the previously approved interest rate on seven-year constant maturity treasury notes plus 60 basis points, adjusted annually. The Company asserted that a four-year recovery period would provide "symmetry between the period over which the Deferred Balance accumulated, and the period over which it is to be recovered." (Petition at 3).

Pursuant to the Board's Order in Docket Nos. ER02050303 *et al.* dated July 22, 2002,[2] by letter dated August 30, 2002, the Company filed supplemental testimony (P-4) addressing its efforts to mitigate the above-market cost of its NUG PPAs, as well as the energy and capacity buyback

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[2] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in its Tariff for Electric Service, Depreciation Rates, and for Other Relief* [balance of caption omitted].

arrangement (Financially Settled Lookback Option ("FSLO")) executed with an affiliate of one of the purchasers of its nuclear units, PSEG Energy Resources and Trade, LLC. The August 30, 2002 filing also included updates of the deferred balances to reflect actual data through July 2002.[3]

On August 29, 2002, the Petition was transmitted to the OAL for determination as a contested case, and subsequently assigned to ALJ Diana C. Sukovich for the purpose of conducting public and evidentiary hearings. ALJ Sukovich conducted a prehearing conference on November 26, 2002, and issued a prehearing order on December 4, 2002 setting forth the nature of the proceeding, the issues to be addressed and a procedural schedule. The ALJ subsequently granted motions for intervention filed by the Independent Energy Producers of New Jersey ("IEPNJ") and the New Jersey Large Energy Users Coalition ("NJLEUC"), as well as motions seeking participant status filed by Rockland Electric Company ("RECO") and PPL Energy Plus, LLC ("PPL").

Cogentrix Energy, Inc. ("Cogentrix") also filed a motion to intervene. On December 9, 2002, the ALJ denied the motion but granted Cogentrix participant status. Cogentrix filed motions for interlocutory review with the Board appealing the denial as well as certain deadlines set forth in the prehearing order. On January 15, 2003, the Board issued an Order affirming the ALJ's rulings. Cogentrix filed a motion for reconsideration on January 30, 2003, which the Board denied by Order dated March 24, 2003.

Upon proper notice, a public hearing was held on January 29, 2003 in Mays Landing. No members of the public appeared or filed comments.

On February 24, 2003, the Phase I Audit Report ("Audit Report") was issued and transmitted to the OAL and the parties. The report was issued in two parts: a *Schedule of Deferred Balances and Attachments for the Three Year Period Ended July 31, 2002 and Independent Accountants' Report* ("Examination Report") (AUD-1), prepared by M&T, and an *Audit of Deferred Balances, Atlantic City Electric Company – Phase I* (AUD-2), prepared jointly by M&T and BWG.

As stated in the Examination Report, M&T's examination of the Company's deferred balances as of July 31, 2002 and its compliance with the relevant Board Orders was conducted in accordance with the attestation standards established by the American Institute of Certified Public Accountants. With the exception of: 1) the still to be determined outcome of a dispute with the Logan NUG over the facility's heat rate; 2) the delayed recording of a tax refund associated with the buyout of the power purchase agreement ("PPA") with the Pedricktown NUG that if booked properly would have reduced buyout interest and the NNC deferred balance

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[3] Updates of Schedules HAC-1, 4, 5, 7, 8 and 9 attached to the Direct Testimony of Company witness Chalk (P-11). By letter dated March 5, 2003, these same schedules were updated to reflect actual data through January 2003. Additional updates were provided in the ongoing monthly deferred balance reports filed with the Board's Energy Division in response to its April 27, 2000 letter requesting this data from the four electric utilities.

by $0.459 million; 3) the amortization of regulatory assets of $2.617 million included in the MTC deferred balance in error; and 4) an overstatement of the Company's allowance for doubtful accounts of $1.417 million, all as discussed more fully below, M&T found that "the Company complied, in all material respects, with the Board Orders regarding the deferred balances for Phase 1." (AUD-1 at 1-2). Based on the data submitted in ACE's August 1 and August 30, 2002 filings, and after reflecting M&T's recommended adjustments, the deferred balances examined and attested to by M&T totaled $164.376 million as of July 31, 2002, consisting of an underrecovered BGS balance of $93.232 million,[4] an overrecovered NNC balance of $6.159 million, an underrecovered MTC balance of $93.908 million, an overrecovered SBC balance of $18.785 million, and interest of $2.180 million.[5] (*Id*., Attachment II).

In addition to providing supporting detail for the Examination Report, the second part of the Audit Report (AUD-2) included a prudence review of the Company's BGS procurement and its efforts to mitigate the above-market cost of its NUG PPAs during the first three years of the Transition Period. As discussed more fully below, BWG recommended a BGS disallowance of $6.119 million as the estimated cost of the Company's failure to purchase the full amount of attractively priced capacity offered in response to an RFP issued to obtain BGS supply during the Transition Period.

The ALJ conducted evidentiary hearings on February 19, 20, 21, 24, and 27, 2003. The Company, the RPA, NJLEUC and Board Staff participated in the hearings. In support of its Petition, ACE presented testimony from Charles F. Morgan, Jr., Manager of New Jersey Restructuring; Jerry A. Elliott, Vice President, Transmission and Distribution Reliability; Herbert A. Chalk, Manager – Revenue Requirements; and Joseph F. Janocha, Business Support Leader – Power Delivery Planning, Finance and Regulatory. NJLEUC offered Michael Gorman of Brubaker & Associates, Inc. The RPA presented consultants Andrea C. Crane, Vice President of The Columbia Group, Inc., and James A. Rothschild, President of Rothschild Financial Consulting as expert witnesses. Also testifying as panels were Christopher Brown, Lenny DeGuzman and William Spang from M&T, and Angela Anderson, Elizabeth Lemkul and Perry Wheaton from BWG, who attested to and were cross-examined on the Audit Report.

The parties filed Initial and Reply Briefs on March 24, and April 7, 2003, respectively,[6] which addressed issues regarding the BGS, MTC, NNC and SBC deferred balances, the method of recovering the deferred costs, the level of ongoing costs to be reflected in the unbundled rate charges, the calculation of interest, and rate design.

By Secretary's letter dated March 25, 2003, the Board advised the ALJs presiding over the deferred balances proceedings of the four electric utilities that, at its March 20, 2003 public

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4 Before BWG's recommended capacity purchase adjustment of $6.119 million.

5 As calculated by the Company in Schedule HAC-9 included with the August 30, 2002 filing.

6 The Company's, RPA's, Staff's and NJLEUC's Initial and Reply Briefs will be denoted herein as "CIB", "CRIB", "RIB", "RRB", "SIB", "SRB", "NJLEUCIB" and "NJLEUCRB," respectively.

meeting, it had voted to recall certain issues related to the securitization/amortization of the deferred balances, including the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized, and for the balances to be amortized, the appropriate length of the amortization period and interest rate. The Board also recalled the issue of whether all or part of the prudently incurred deferred balances were legally eligible for securitization, and indicated that the individual ALJs should make findings as to what the level of prudently incurred deferred balances is for each utility.

On June 2, 2003, ALJ Sukovich filed her Initial Decision with the Board. Exceptions were filed by the parties and Cogentrix on June 23, 2003. Replies to the Exceptions of the other parties were filed by the Company and the RPA on June 30, 2003.

At its June 16, 2003 public meeting, the Board voted to seek a 45-day extension of the effective date of the ALJ's Initial Decision until August 29, 2003. The request for the extension was predicated upon the Board's need for additional time for review of the record. At a special public meeting held on July 21, 2003, the Board rendered an oral decision in this matter, which was followed by the issuance of a written Summary Order on July 31, 2003.

III. THE ISSUES – POSITIONS OF THE PARTIES

A. <u>BGS DEFERRED BALANCE</u>

As set forth in the Final Restructuring Order, during the first three years of the Transition Period ACE was to secure its BGS supply from power purchases made pursuant to its NUG PPAs, the generation from its to be divested ("TBD") generating units prior to their divestiture, and power obtained via an RFP process:

> ACE shall apply both NUG contract power and to-be-divested owned generation power (prior to the closure of the sale of the generation assets) towards the BGS supply requirement, which power shall be credited at the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin). Such credited prices shall be employed for purposes of establishing the level of the NNC and establishing the level of owned generation revenue requirement recovery (prior to the completion of divestiture), in accordance with this Order. During the first three years of the Transition Period, up to and including July 31, 2002, ACE shall solicit requests for proposals ("RFP Process") for the provision of wholesale supply for BGS in twelve month pricing cycles, or such other cycles as ACE deems necessary or prudent. ACE will submit its plans for the RFP Process to the BPU by September 15, 1999. ACE shall commence the RFP Process as soon as practicable after such date and approval of the plan by the BPU,

> with the goal of concluding such process and entering into a contract for BGS supply by December 15, 1999. Any agreements for the provision of BGS shall be presented to, and subject to the approval of, the BPU.
>
> [Final Restructuring Order at 87, paragraph 7].

The Company was also given the option of obtaining energy and capacity through one or more parting contracts negotiated with the purchasers of its generating units, as well as the ability to use hedging and other financial instruments to decrease ratepayer exposure to price spikes and volatility. In authorizing the use of these instruments, the Board recognized that they could result in costs in excess of the spot market, but to the extent prudently incurred, they, as well as the cost of parting contracts and other BGS-related costs, would be recoverable in rates. (*Id*. at 88, paragraph 11).

As summarized in Exhibit 1 attached, 38.5% of the Company's BGS supply during the first three years of the Transition Period was obtained from its TBD generation, 34.2% from NUGs, 15.1% from contracts with third parties and bilateral contracts, and 12.2% from PJM. The total cost of this supply was $1.853 billion, of which $611 million (33.0%) was for the recovery of the revenue requirement of the TBD generating units, $723 million (39.0%) for purchases made under NUG PPAs, $316 million (17.1%) for other contractual purchases of energy and capacity, and $203 million (10.9%) for capacity and energy purchased in the PJM spot market.

Prudence of BGS Procurement - Company's Position

Contending that its energy purchases throughout the Transition Period were consistent with market conditions, the standard set forth in N.J.S.A. 48:3-57.a., ACE asserted that its BGS procurement process was reasonable and prudent, and thus that its procurement costs are fully recoverable. (CIB at 16).

How the Company's RFP process was conducted during the Transition Period was explained and supported in the Direct and Rebuttal Testimony of Company witness Elliott (P-7 and P-8). With the help of a consultant, the Company first developed an RFP for "full requirements service" (all of Atlantic's BGS supply not obtainable from its NUGs, other contractual purchases and the generation from the TBD units) for the period from January 1, 2000 through July 31, 2002 ("RFP I").[7] Retail choice was just beginning in New Jersey, thus it was difficult to estimate how many customers would choose third party suppliers ("TPS") for generation service. Nor could it be known with certainty when the Company's generating units would be divested. These uncertainties as well as potential buyouts of the Company's NUG contracts combined to make the volume risk to prospective bidders so great that none expressed an interest in responding to such an RFP. (P-7 at 2-3).

[7] For ease of reference the RFP designations employed in the Audit Report (AUD-2) have been used here as well. For a concise summary of the RFPs, see Exhibit VIII-4 on page VIII-6 of the Report.

A second RFP ("RFP IA") sought varying amounts of energy and capacity for the period from January 1, 2000 through May 31, 2000 on the assumption ACE's fossil and nuclear units would be divested by then. Two bids were received, and rejected on the basis that energy and capacity was likely to be available from the PJM spot market at lower cost. (*Id*. at 3-4).

Witness Elliot further testified that in addition to the load uncertainties noted in connection with RFP I, changes in the rules governing PJM's capacity market prompted ACE to utilize a "portfolio approach" in its next RFP ("RFP II"), filed for the Board's approval on March 14, 2000, in which bids for the supply of both 300 megawatts ("Mw") and 350 Mw of capacity and energy for the months of June through August 2000 were sought. Bids for the 350 Mw, the approximate capacity of ACE's nuclear units, were sought in the event the units would be divested by June. At the Board's request, the RFP was amended to extend the term of the request for the 300 Mw to a full year, in the hope that would yield more favorable bids. All bids were rejected, however, with the Company again opting to rely on the spot market, which it judged would result in lower costs as compared to the RFP offers. (*Id.* at 5-6).

ACE's next RFP ("RFP III"), issued in September 2000 sought to purchase 400 Mw of capacity and varying amounts of on-peak energy for the period from January 2001 through July 2002. Nine bids for energy and one bid for capacity were received. The energy bids were deemed competitive relative to the forecasted spot market, and the low bid was accepted. The capacity bid appeared to be competitive, but having received only one bid, ACE was concerned that it did not demonstrate a truly competitive result, and accepted only 200 Mw. (*Id*. at 7).

The final RFP ("RFP IV") was issued in April 2001. In it, ACE sought capacity for the period from June 2001 through September 2002, and on-peak energy for the months of July and August 2001 and July 2002. One bid for energy and two bids for capacity, each for 400 Mw, were accepted. (*Id*. at 9). The Company's BGS supply in year four of the Transition Period (August 1, 2002 through July 31, 2003) was obtained pursuant to the statewide auction approved by the Board by its Order in Docket Nos. EX01050303, *et al* dated February 15, 2002.[8]

<u>BGS Disallowances Proposed by the RPA</u>

In judging whether ACE acted reasonably and prudently, the RPA asserted that the Company's managerial conduct should be evaluated "in light of the circumstances, information and options in existence at the time when management decisions were made." The RPA further argued that, based on the standard of review employed by the Board in Public Service Electric & Gas Company's ("PSE&G's") Hope Creek proceeding,[9] ACE must additionally show "why each BGS

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8 *I/M/O the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act, <u>N.J.S.A.</u> 48:3-49 et seq.*, Docket Nos. EX01050303, EO01100654, 655, 656 and 657.

9 *I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Rates – Hope Creek Proceeding,* Docket No. ER85121163, Order dated April 6, 1987. At issue were the costs incurred in constructing PSE&G's Hope Creek nuclear unit.

cost was incurred and the benefits derived by the Company's actions." The Final Restructuring Order also imposed a clear obligation on the Company to mitigate risk. (RIB at 9-11).

By these standards, the RPA contended that ACE's actions during the Transition Period were neither prudent nor reasonable, and recommended an aggregate disallowance of its BGS deferrals of $40.523 million, as derived and explained in the Direct Testimony of witness Crane and summarized in the RPA's Initial Brief. (RA-2 at 17-25; RIB at 5).[10] The recommended disallowances included $25.527 million of the cost of third party purchases made in the months of July and August 2001 deemed excessive, $3.375 million of capacity purchases assertedly resold at a loss during the first three years of the Transition Period, and BGS administrative costs of $3.528 million incurred and projected to be incurred during the Transition Period. The RPA further proposed crediting interest of $1.993 million to the beginning BGS deferred balance (the overrecovered balance of ACE's discontinued Levelized Energy Adjustment Clause ("LEAC")), and accepted the Auditors' recommended capacity purchase disallowance of $6.100 million.

In support of its proposed disallowances the RPA argued that ACE's inability to issue a successful RFP until well after the Transition Period had begun, and within a reasonable price range, was imprudent and resulted in excessive BGS costs. The RPA also criticized ACE for not complying with BPU directives, as evidenced by its failure to submit an RFP plan to the Board by the mandated September 15, 1999 date, and for not having entered into long-term purchased power contracts in December 1999, as anticipated by the Final Restructuring Order. Nor did the Company use financial hedges to protect against excessive price spikes or enter into parting contracts with the purchasers of its divested generating assets.

The RPA further contended that ACE's imprudence was in part a result of its employees' lack of the basic tools and training to provide the minimum acceptable level of expertise in a newly regulated environment, as evidenced by the Auditors' findings that the Company did not have sufficient qualified personnel. Moreover, the employees charged with managing BGS supply were not provided with the necessary reports and analytical resources to consistently make effective BGS supply procurement decisions. (RIB at 17; AUD-2 at I-10 to I-11, VIII-25). In a deregulated environment, the RPA averred, the Company had a particular obligation to ensure that its employees were sufficiently knowledgeable and able to make reasonable and prudent decisions to protect the interests of its ratepayers.

The RPA's recommended BGS disallowances are discussed in more detail below:

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[10] The disallowances determined in RA-2 were based on actual data through October 2002, and were updated in the RPA's Initial Brief to reflect actual data through January 2003.

1. Third Party Purchases, July/August 2001

In recommending that $25.527 million of the cost of the Company's July and August 2001 third party purchases be disallowed, RPA witness Crane noted that ACE's BGS deferrals in these months alone totaled over $78 million, and argued that the Company's entire BGS deferred balance of $49 million might have been avoided if it had better managed its costs in just these two months. That, she contended, could have been accomplished if ACE had entered into long-term purchased power contracts in December 1999, as anticipated by the Final Restructuring Order. Alternatively, ACE could have entered into hedging agreements to protect against excessive price spikes. (RA-2 at 17-18). In quantifying the disallowance, the RPA proposed that the recovery of the cost of the third party purchases be limited to the cost of the Company's TBD generation and NUG power in these two months, or $73.66 per Mwh and $70.50 per Mwh in July and August 2001, respectively, as compared to the actual cost of the third party purchases in these months of $122.52 and $116.53 per Mwh. Applying the difference between the actual and allowable cost per Mwh to the 262 gigawatthours ("Gwh")[11] and 276 Gwh of third party purchases made in July and August 2001 yielded recommended disallowances of $12.821 million and $12.706 million for these months, respectively. (RA-2 at 18-19; Schedule ACC-4).

The Company's Rebuttal

In refuting the RPA's contention that ACE should have been able to enter into long-term contracts in 1999, Company witness Elliott reiterated ACE's experience in preparing its initial RFP in the fall of that year, when it surveyed 80 potential suppliers and found none willing to bid. (P-8 at 3). Virtually all of the suppliers told ACE there was too much price and volume uncertainty to allow them to make such a commitment over such an extended period. Over the three year period, for example, ACE's BGS load varied by nearly 600 Mw due to customers switching to third-party suppliers and then returning to BGS. In addition, there was uncertainty as to when ACE's generating units would be divested. Equally uncertain and volatile were energy and capacity prices, especially the latter, due to evolving PJM rules. Nor, in the Company's view, was witness Crane's quantification appropriate, in that it compared peak period summer costs to the year-round cost of serving base or intermediate load, the service to which ACE's NUGs and TBD units are devoted. (*Id*. at 4-13).

NJLEUC's Position

While it did not address the RPA's proposed disallowance directly, NJLEUC was highly critical of ACE's BGS procurement during the Transition Period and proposed a disallowance of its own. In briefing the issue, NJLEUC first reviewed the guidance and supply options set forth in the Final Restructuring Order (at 78, second paragraph; at 80, second paragraph; at 87,

[11] A gigawatthour is a thousand megawatthours. A megawatthour is a thousand kilowatthours, thus a gigawatthour is a million kilowatthours.

numbered paragraphs 7 and 9; and at 91, numbered paragraph 20).[12] Recognizing the many uncertainties the Company faced at the beginning of the Transition Period, among them the anticipated level of customer switching to third party suppliers, changing regulation in the industry and the cost of energy and capacity in the PJM spot market, the Board had provided the Company with clear and specific guidance for mitigating market risk, a prominent concern of the Board at that time. To reduce this risk, the Board directed the Company to devote its TBD generating units and NUG purchases to BGS supply, priced at the floor shopping credit, thereby insuring that a substantial portion of the supply would be provided at a pre-established price. In addition to the RFP process, other risk mitigating options the Company was encouraged to pursue included hedging instruments and parting contracts with the purchasers of its TBD generating units. This guidance notwithstanding, NJLEUC contended that the Company had "inexplicably assembled a BGS supply organization that was woefully inadequate to accomplish the task at hand…failed, until pressured by others, to enter into parting arrangements that could have provided substantial and reasonably priced firm supply from its divested generation" and "failed to utilize financial instruments for hedging purposes as the Board had also recommended." (NJLEUC IB at 12-15).

Citing the Auditors' findings, NJLEUC further contended that the Company's BGS procurement effort was understaffed, inexperienced and ill-informed from the start. As a result, it was characterized by a "series of misguided initiatives, questionable decisions, and violations of the Board's Final [Restructuring] Order," as exemplified by the ill-fated full requirements RFP prepared in late 1999 that failed to elicit a single response from any of the 89 suppliers to whom it was forwarded. The next RFP, filed some six months after the September 15, 1999 deadline established by the Board,[13] inappropriately sought the Board's pre-approval, and prompted the directive in the Board's May 15, 2000 Order[14] requiring the Company to solicit bids for a 12-month supply in addition to the three-month supply sought by the RFP. (*Id*. at 17-21).

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12 Although the Final Restructuring Order was not issued until March 30, 2001, the guidance NJLEUC cites was contained in the Summary Restructuring Order issued on July 15, 1999, and in the June 9, 1999 Stipulation of Settlement approved, with modifications, by the Summary Restructuring Order, a comment that applies to cites to the Final Restructuring Order generally.

13 As specified in the Summary Restructuring Order.

14 Issued in Docket No. EM00030156, *I/M/O the Petition of Atlantic City Electric Company for Approval of a Request for Proposals, Authorization of a Competitive Procurement and to Enter into a Contract for Basic Generation Service Supply*. This Order directed the Company to add a 12-month option to the three-month term proposed for the purchase of the 300 Mw of capacity and energy for June, July and August 2000, and pending the Board's decision on the Company's petition for approval of the sale of its nuclear units, additionally directed the Company to omit the 350 Mw contingently sought in the event the nuclear units were to be divested by June 1, 2000. Following the Board's approval of the sale of the nuclear units at its public meeting on May 10, 2000, by Order in this same Docket dated May 30, 2000, the Company was authorized to proceed with the 350 Mw solicitation in combination with the FSLO discussed in more detail below.

NJLEUC also took the Company to task for failing to negotiate parting contracts with the purchasers of its TBD generating units, and in particular, for failing to enter into a supply arrangement with Conectiv Energy Services, Inc. ("CESI"), its unregulated affiliate to which the formerly owned Deepwater plant and approximately 500 Mw of combustion turbine capacity had been transferred, as PSE&G did with its unregulated affiliate, PSEG Power LLC, for the supply of its entire BGS requirement during the first three years of the Transition Period. Delays caused by the Company's failure to negotiate a parting contract with NRG Energy, Inc. ("NRG"), the entity to whom the Company had proposed to sell its fossil units, as well as the unexpected presence of Deepwater among the assets proposed to be sold, were also cited as having been at least partially responsible for the failed sale of the fossil units. (*Id.* at 23-27).

Thus viewed as a whole, NJLEUC contended that "it can easily be concluded that Atlantic's BGS procurement practices…were clearly flawed," and NJLEUC accordingly recommended that of the Company's July 31, 2003 deferred BGS balance of $49 million projected at that time,[15] $24.5 million be disallowed to "more equitably apportion the consequences of Atlantic's unreasonable and imprudent procurement practices." (*Id*. at 4-5).

Staff's Position

While recognizing that ACE faced many challenges during the Transition Period, some beyond its control, Staff nonetheless maintained that the Company could have done a much better job of procuring its BGS supply. The Company's failure to negotiate a parting contract with the purchasers of its nuclear units, and even to renew the FSLO upon the "virtual sale"[16] of these units was, in Staff's view, a particularly significant example of the missed opportunities cited by witness Crane in support of the RPA's recommended disallowances:

> I just think the [sic] that the Board needs to recognize that in fact the Company did have a certain degree of control over its actions. We don't know, none of us know here today what would have happened if the Company had complied with the Final Restructuring Order, if they had filed some sort of RFP proposal in a timely manner with the Board in 1999…but certainly there were actions that the Company should have taken in light of the Final Restructuring Order that it did not take, and I think that's kind of where we have to step back and say this is the situation we're faced with today, what is an equitable, fair and reasonable resolution?

[15] As filed, based on actual data through June 2002 (Schedule HAC-10, P-11).

[16] As discussed more fully below, on October 7, 2000, the Company entered into an agreement with an affiliate of one of the purchasers of its nuclear interests under which the purchasers received an entitlement to the energy and capacity of the nuclear units in exchange for reimbursing the Company for the units' operation and maintenance costs, including fuel, and capital expenditures through October 18, 2001, the actual sale closing date.

[Tr. 618-619].

On cross examination, RPA witness Crane placed the RPA's proposed disallowance of the excessive cost of the third party purchases within the broader context of the Company's failure to avail itself of the many options it should have considered throughout the Transition Period:

> What I'm looking at is over the period of the entire three years of the Transition Period…were your actions reasonable from beginning to the end…There are other choices that the Company could have made earlier on. They could have investigated parting contracts when they sold their nuclear facilities. They could have investigated parting contracts with their fossil fuel facilities, which perhaps would have sped up that regulatory process with regard to the approval of the fossil plants. They could have investigated further hedging opportunities.
>
> So they could have taken a host of actions that would have resulted in them being in a position by July and August of not facing a $78 million deferral.
>
> Again, my disallowance is not focused on the specific RFP that you might have put out at one point in time and whether you made the right or wrong decision in response to that proposal, it's based on the totality of management's actions during this process.
>
> [Tr. 713-715].

Staff accordingly supported the RPA's recommended BGS disallowance, and to assess its reasonableness within the context of ACE's overall performance during the first three years of the Transition Period, compared the cost of the Company's "discretionary" purchases (purchases other than from NUGs and other long-term contractual purchases entered into prior to the Transition Period) to the estimated cost of energy and capacity that would have been incurred if the same energy and capacity had been purchased from PJM, as quantified in Appendix SIB-2 of Staff's Initial Brief. As shown in Schedule JAE-1 (Revised) attached to the Rebuttal Testimony of witness Elliott (P-8), the actual cost of the Company's "PJM Markets" and "Other Contracts" purchases was $518.8 million during the first three years of the Transition Period as compared to Staff's estimated $353.5 million if the same energy (7,168 Gwh) and capacity had been purchased from PJM – a difference of $165.3 million.[17] On a unit cost basis,

[17] After eliminating the pre-Transition Period (March 1998) PECO energy and capacity purchase inadvertently included in Atlantic's discretionary purchases by Staff, the difference is $177.1 million (6,597 Gwh times ($75.90 per Mwh - $49.06 per Mwh)), as discussed below. The revised PJM cost of $49.06 per Mwh was determined by subtracting the Mwh of PECO purchases in the months of August 1999 through May 2000, as shown in Schedule 1(c) attached to Schedule JAE-1 (Revised), from the "Contracts" column on page 2 of Appendix SIB-2 attached to Staff's Initial Brief.

the average actual cost of ACE's discretionary purchases was $72.38 per Mwh, as compared to an estimated $49.32 per Mwh if the same energy and capacity had been purchased from PJM. (SIB at 40).

Staff also compared the cost of ACE's discretionary purchases to the cost of the equivalent purchases incurred by Jersey Central Power & Light Company ("JCP&L") and RECO over the first three years of the Transition Period.[18] As shown in Appendix SIB-3 attached to Staff's Initial Brief, the cost of JCP&L's discretionary purchases averaged $49.7 per Mwh, and RECO's $55.5 per Mwh over the period. If ACE been able to procure power at the same cost, its BGS procurement costs would have been lower by $163 million and $122 million, respectively.[19] (*Id*. at 40-41). Given this poor performance compared to that of the State's two other similarly-situated electric utilities, Staff found the energy and capacity cost disallowances recommended by the RPA to be fully justified.

2. Excess Capacity Purchases

The RPA's proposed excess capacity disallowance of $3.375 million was quantified in Schedule ACC-5 attached to R-2. As shown there, in each month in which both purchases and sales of capacity were made, the difference between the average cost per Mw of the purchases and the lower amount per Mw received from the sales was applied to the Mw sold, and the resultant amount recommended for disallowance on the basis that ratepayers should not be asked to pay for higher-priced excess capacity sold below cost.

The Company's Rebuttal

Extreme volatility in capacity prices during the period, as well as the factors described above that made it extremely difficult to estimate the Company's load, particularly unanticipated increases attributable to customers returning from third party suppliers and the timing of the generating unit divestitures, were cited by ACE in defense of its capacity purchases and sales during the Transition Period. (P-8 at 14-20).

ACE additionally argued that the RPA's methodology was arbitrary and mechanistic, and produced inappropriate results. For example, the Company asserted that in February 2002 it bought 100 Mw from Exelon at a cost of $0.186 million, and sold 100 Mw to Exelon in that same month, for which it received $0.195 million. Under Ms. Crane's method, the apparent profit of $9,000 on this sale, the only sale occurring in the month, became a disallowance of over $0.2

[18] Parting contracts were also considered discretionary in making this comparison since all three utilities (the parent company in RECO's case) divested their generating assets during the Transition Period, and thus could have chosen to either enter or not enter into such contracts.

[19] After eliminating the pre-Transition Period PECO purchase and making a similar adjustment to the JCP&L data, the differences are $157.9 million and $135.3 million for JCP&L and RECO, respectively, based on adjusted ACE discretionary purchases of 6,597 Gwh having an average cost of $75.90 per Mwh, as compared to an adjusted average cost of $51.97 per Mwh for JCP&L and $55.38 for RECO, as shown in Exhibit 3 attached and discussed below.

million simply because the average price paid for capacity in that month was considerably higher than the per Mw price obtained from Exelon. The Company argued that similar profits turned into losses when the method was applied to the other four sales of capacity made to Exelon during the January through May 2002 time period. (CIB at 21; Schedule 1(e) included in Schedule JAE-R4 attached to P-8).

Staff's Position

Staff supported the RPA's recommended excess capacity disallowance for the same reasons it supported the recommended disallowance of the cost of the July and August 2001 third party energy purchases deemed excessive.

3. BGS Administrative Costs

The RPA contended that ACE had not demonstrated the reasonableness of its claimed BGS administrative costs of $3.528 million, nor that it was necessary to include them in the BGS deferral, since administrative costs are normally recovered in base rates. Moreover, the Company's financial integrity did not appear to have suffered from the incurrence of these costs. (RA-2 at 23-24).

In rebuttal, ACE asserted that these costs were appropriately incurred in administering BGS supply for its customers, and could not be recovered by the Company's current base rates, since those rates were last set in 1991. Additionally, all generation-related costs were eliminated from ACE's distribution rates as a result of the unbundling of the Company's rates in the Board's restructuring proceedings. (P-5 at 4-5).

In lieu of the disallowance proposed by the RPA, Staff recommended that these costs undergo further review in ACE's base rate proceeding. (SRB at 8; Appendix SRB-1).

4. LEAC Interest

The RPA maintained that the interest calculation methodology employed with ACE's previously effective LEAC called for annual true-ups and interest calculations, not the netting out of monthly over and underrecoveries over the entire 26-month period the LEAC was in effect, as assumed by the Company in making its interest calculation (the calculation shown in Schedule HAC-2 attached to P-11). (RA-2 at 20-22). Witness Chalk defended the Company's calculation, asserting that it was consistent with N.J.A.C.14:3-13**,** the Board's regulation that specifies how interest on adjustment clause over and underrecoveries is to be determined. (P-13 at 2-5). NJLEUC took no position on the issue, nor did Staff in its Briefs. Staff did, however, agree with the Company in its Exceptions to the Initial Decision filed with the ALJ.

5. Auditors' Findings/Recommendations

In performing its prudence review, the Auditors employed the following standard: "Did management make the decisions and take the actions that a reasonable individual would have, given the alternatives and information available at the time such decisions and actions were taken, consistent with legislative and other regulatory requirements?" (AUD-2 at II-28). The Auditors (BWG) then performed a detailed review of ACE's BGS procurement during the first three years of the Transition Period, and presented their findings in Chapter VIII of the Audit Report. As set forth in the Findings and Conclusion section of that chapter, they were as follows:[20]

1. At the outset of the transition period, ACE did not have a full understanding of what the BGS supply process would entail and did not take adequate steps to establish an experienced BGS supply organization.

2. ACE did not retain an outside consultant to provide the necessary expertise and guidance to effectively assist in the BGS supply efforts until the conclusion of RFP II, in June 2000. Although ACE did not use a competitive process to select the consultant, the management of its BGS supply RFP process improved significantly after Lexecon [an outside consultant] was retained.

3. Throughout the first three years of the transition period ACE had limited in-house staff and did not have adequate analytical resources to consistently make effective decisions regarding BGS supply procurement.

4. ACE was reluctant to take any action without the full support of the BPU. This affected the outcomes of RFP I and III as well as the nuclear plant divestiture process.

5. ACE did not meet its commitment to file for the BPU's approval of the RFP process by September 15, 1999, as set forth in its Stipulation and approved in the Summary Order.

6. ACE's actions with respect to RFP I were flawed, both in the development of the RFP itself, and in the analysis and decision making process regarding the results of the RFP.

7. The RFP II process did not elicit any acceptable bids.

8. RFP III was moderately successful, resulting in acceptable bids for energy and capacity. However, due to concerns about whether the BPU would consider the process to be competitive, ACE decided to only take one-half of the capacity requested.

9. ACE's actions and decisions regarding RFP IV were reasonable.

[20] Although Findings 11 through 14 relate to the deferred MTC balance, for completeness they have been included here.

10. ACE's use of Deepwater and CT [combustion turbine] capacity for BGS in the August 1999 through July 2000 period was not in compliance with the Final Order that requires the capacity to be offered to PJM at market prices.

11. While it is possible that ACE could have taken steps to expedite the proceedings related to its fossil units and thereby accomplish its fossil divestiture, the termination of the sale is ultimately attributable to the delay in the receipt of the Board Order approving the sale.

12. Since the start of the transition period, O&M and fuel costs for the B. L. England generating station have increased, while the costs for comparable plants have remained stable. Concurrently, B. L. England's performance as measured by availability factor, capacity factor, and equivalent forced outage rate has declined.

13. An examination of the operation of B. L. England in periods of significant congestion in the ACE load zone indicates that there are instances in which ACE's ability to respond to transmission congestion was limited by forced outages and reserve shutdowns of the B. L. England units.

14. With the exception of Hope Creek, the production costs for ACE's jointly owned To-Be-Divested plants generally remained the same since the start of the transition period. Hope Creek had significantly higher costs in 2000 due to an extended outage that lasted over two months.

[AUD-2 at VIII-23 to VIII-52].

Despite the deficiencies noted with respect to RFPs I and II, it was not clear to the Auditors that these shortcomings had a quantifiable cost impact. (AUD-2 at I-12; VIII-56). Based on their other findings the Auditors recommended that: 1) the payments for Deepwater and CT capacity made in 1999 and included in the BGS deferred balance be re-priced at PJM's monthly clearing prices,[21] and that the Company be required to demonstrate that the capacity from these units was needed for BGS supply from August 1999 to July 2000; 2) the estimated $6.119 million cost of ACE's decision to accept only 200 Mw of the 400 Mw capacity bid in response to RFP III for the period January 1, 2001 through July 31, 2002 be disallowed; 3) a detailed review of ACE's operation and maintenance of B. L. England be performed in light of the plant's cost and performance trends and the impact of its forced outages and reserve shutdowns on its use for

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[21] The payments made by the utility for Deepwater and CT capacity in the months of January through July 2000 were based on PJM's monthly capacity clearing prices. In the months of August through December 1999, the payments were based on the actual cost of Deepwater and CT capacity. Apart from the pricing issue, the Auditors noted that this use of the Deepwater and CT capacity (selling it to the utility) was not in compliance with the Final Restructuring Order. (AUD-2 at I-11).

congestion management; and 4) the energy and capacity cost data provided by ACE and included in Exhibits VIII-10 through 13 of the Audit Report be verified, and an analysis of the differences in the cost of ACE's BGS purchases and the cost of energy and capacity based on PJM market prices be performed.[22] (*Id*. at VIII-56).

6. BGS Charges Effective August 1, 2003

Although not the subject of the Company's Petition or at issue in this proceeding, effective August 1, 2003, the Company implemented changes in its BGS rates to reflect the winning bids accepted in the statewide auction conducted in February 2003, as approved by the Board in its Order dated February 6, 2003 in Docket No. EX01110754, *I/M/O the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. – Basic Generation Service Auction Results.* For fixed price BGS, the winning bid was 5.260 cents per kwh, as compared to the price of 5.117 cents per kwh for auction power obtained for BGS supply in year four of the Transition Period. A further change, to 5.473 cents per kwh, was implemented on June 1, 2004, as approved by the Board in Docket No. EO03050394, *I/M/O the Provision of Basic Generation Service for Year Two of the Post-Transition Period – Auction Results*, Order dated February 11, 2004. In all cases, the prices include the cost of energy, capacity, ancillary services and transmission.

B. MTC DEFERRED BALANCE

As stated in the Final Restructuring Order, ACE made a business decision to divest its ownership interests in its fossil and nuclear units via a Board-approved auction process, after which the Board was to determine the units' stranded costs. The remaining generating units, the 220 Mw coal and oil fired Deepwater plant and 523 of gas and oil fired combustion turbine capacity were to be transferred to an unregulated affiliate at book value. (Final Restructuring Order at 79, 89, 91; Schedule B attached to the June 9, 1999 Stipulation of Settlement approved, with modifications, by the Final Restructuring Order). By Order dated January 4, 2000, the Board approved the process and procedures to be followed as well as the standards

[22] Substantial revisions in the costs and Mwh shown in Schedule JAE-1 included as an attachment to P-7 and P-8 and in R-2 were made during the course of the proceeding. As filed (with P-7), this schedule indicated that the total cost of the Company's energy supply during the first three years of the Transition Period was $1.651 billion, and its energy requirement was 26,465 Gwh. In a November 10, 2002 revision included in RA-2, total costs were revised upward to $1.730 billion, including an increase in the "Other Contracts" category of $39 million, and the energy requirement was revised to 27,554 Gwh. In a second revision included in P-8 filed on January 24, 2003, total costs were increased to $1.853 billion and the energy requirement was revised downward to 26,285 Gwh. The second revision included an increase of $110 million in "PJM Markets" costs and an increase of $13 million in "Other Contracts" costs. The revisions were addressed in S-2 and in the cross-examination of witness Elliott at Tr. 217-223 and Tr. 353-360, and assertedly affected only Schedule JAE-1, and not witness Chalk's schedules on which the Company's asking was based. While the costs shown in the "Generation" and "NUGs" categories of JAE-1 (Revised) included in P-8 agree with those shown in Schedule HAC-4 of witness Chalk's testimony, the sum of the "Other Contracts" and "PJM Markets" categories is $518.817 million, as compared to $517.922 million shown for energy capacity purchases and sales in HAC-4.

to be met in divesting the Company's generating units.[23] The sale of its ownership interests in the Salem, Peach Bottom and Hope Creek nuclear units, aggregating approximately 380 Mw of capacity, to PSEG Power, LLC and PECO Energy Company was approved by Board Orders issued on July 21, 2000 and September 17, 2001.[24] By Order dated February 20, 2002, the Board approved the sale of ACE's coal and oil-fired B. L. England station (447 Mw) located in Cape May County, and its ownership interests in Keystone (42 Mw) and Conemaugh (66 Mw), mine-mouth coal-fired stations located in central Pennsylvania (collectively the "fossil units"), to NRG Energy, Inc.[25] However, on April 1, 2002, NRG terminated the agreement for the purchase of these units in accordance with its terms.[26] In May 2002, ACE re-offered its ownership interests in the fossil units for sale, but no acceptable bids were received, and the second attempted sale was terminated in January 2003.

Prior to divestiture, the Final Restructuring Order provided for the generation from the to-be-divested units to be devoted to the supply of BGS during the Transition Period. The revenue received from ACE's MTC, as well as the revenue from supplying BGS, was to be applied to the revenue requirement of the units as follows:

> During the period between August 1, 1999 and completion of the divestiture of generation assets, MTC revenues shall be applied to

[23] In Docket Nos. EM99080605 and EM99080606, *I/M/O the Request of Atlantic City Electric Company for the Establishment of Auction Standards for the Sale of Certain Non-Nuclear and Nuclear Generating Units*, respectively.

[24] In Docket No. EM99110870, *I/M/O the Petition of Atlantic City Electric Company for Approval of the Sale of its Nuclear Generating Units/Regarding the Sale of Nuclear Assets*. The July 21, 2000 Order approved the sale of the nuclear units and the September 17, 2001 Order made a preliminary determination of the units' stranded costs. Pending the issuance of the September 17, 2001 Order, a "virtual" sale to the purchasers, under which they received an entitlement to the energy and capacity of the nuclear units in return for reimbursing the Company for the units' operating and maintenance costs including fuel, and capital expenditures was executed on October 7, 2000. The actual sale closed about a year later, on October 18, 2001. Recovery-eligible nuclear stranded costs of $278 million, net of tax, were securitized on December 19, 2002, pursuant to the Board's Bondable Stranded Costs Rate Order ("BSCRO") issued in Docket No. EF01060394 on September 20, 2002. Also securitized at that time were $139 million and $4 million of net of tax stranded costs associated with the buyout of the Pedricktown NUG PPA and the buydown of the PPA with the DRMI/Ref-Fuel NUG, respectively. Upon the implementation of the Transition Bond Charge ("TBC") and related MTC-Tax in December 2002, the return on the stranded costs of the nuclear units at 13% pre-tax and the Pedricktown buyout interest were eliminated from the MTC.

[25] In Docket No. EM00020106, *I/M/O the Petition of Atlantic City Electric Regarding the Sale of Certain Fossil Generation Assets*. Deepwater was also included in the sale.

[26] In May 2003, NRG and certain of its affiliates filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York, *In re NRG Energy, Inc. et al.*, Case No. 03-13024.

> owned generation revenue requirements, including continued depreciation of assets, and return on investment, operating and maintenance expenses and fuel expenses, and, between the time of divestiture closing and time of securitization closing, MTC revenues shall be applied to provide a return on the net owned generation stranded costs at 13.0% pre-tax. At time of the termination of the MTC (upon the establishment of the TBC [Transition Bond Charge]), total MTC revenues and market revenues received from the crediting of owned generation power to BGS in accordance with paragraph 7 (as modified) will be reconciled to the amounts indicated, including a review of the prudence and reasonableness of the Company's operation of the units, and the Deferred Balance will be reconciled accordingly to reflect a resulting shortfall or excess.
>
> [Final Restructuring Order at 92, paragraph 22].

If the above sources of revenue were not sufficient to recover the revenue requirement of the TBD units, the shortfall was to be included in ACE's MTC deferred balance, on which interest was to be accrued at the rate on seven-year constant maturity treasury notes, as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year, plus 60 basis points. (*Id.* at 82).

For purposes of its inclusion in BGS supply, the energy from the TBD units was to be priced at ACE's "floor" shopping credit,[27] less the cost of transmission, the 6% New Jersey Sales and Use Tax ("SUT"), line losses, ancillary services and a capacity reserve margin. (*Id.* at 87). To the extent the revenue received from providing BGS was insufficient to recover the revenue requirement of the TBD units, the difference (the component in excess of the shopping credit) was recoverable by the MTC, or if still not recovered, included in the MTC deferred balance.

In addition to the above-market cost of TBD generation, the Final Restructuring Order authorized the inclusion of restructuring-related capital and operating costs in the MTC. Reasonable and verified restructuring costs of a capital nature, as set forth in Schedule C of the June 9, 1999 Stipulation of Settlement approved, with modifications, by the Final Restructuring Order, net of other sources of recovery that could be applied towards such costs, including TPS fees, were to be amortized over a period not to exceed eight years, with a pre-tax return of 13.0% allowed on the unamortized balance. (*Id.* at 92-93). The recovery of restructuring-related operating costs other than consumer education costs, as set forth in Schedule D of the Stipulation, was also to be net of other sources of recovery (*i.e.,* TPS fees), and subject to a reasonableness and verification review. (*Id.* at 93).

[27] ACE's shopping credits were set as the higher of the market-based cost of BGS, as defined in and subject to the limitations set forth in paragraph 6 on pages 86-87 of the Final Restructuring Order, and the floor shopping credits appearing on page 85 of the Order.

RPA's Recommended MTC Disallowances

In her Direct Testimony filed on January 3, 2003, RPA witness Crane proposed disallowing a total of $40.993 million of costs included in ACE's MTC deferred balance, based on actual data through October 2002. (RA-2 at 44; Schedules ACC-1, ACC-8) The recommended disallowances were updated in the RPA's Initial Brief to reflect actual data through January 2003[28] and the Auditors' findings as follows:

- o Post-August 1, 2002 above-market cost of the TBD fossil units, net of an allowance for a return on the units' imputed stranded costs -- $29.569 million;
- o Return on cash working capital included in the revenue requirement of the TBD units (fossil and nuclear) -- $3.793 million;
- o Amortized and annual restructuring-related operating costs -- $15.307 million;
- o Consolidated TPS billing costs -- $4.052 million;
- o Auditors' recommendation, regulatory asset amortization included in the MTC balance in error -- $2.617 million.
- o Total recommended MTC disallowances -- $55.338 million.

[RIB at 5].

The proposed disallowances are discussed individually below:

1. Above-Market Costs of TBD Fossil Units

RPA's Position

As explained in witness Crane's Direct Testimony, the disallowance of the above-market costs of the TBD fossil units was quantified by taking the difference between the total revenue requirement of the TBD units shown in Company witness Chalk's Schedules HAC-7 (actual) and HAC-13 (forecast), and the portion of the revenue requirement included in BGS recoverable costs, also shown on those schedules, and from these monthly differences, subtracting carrying costs on the post-divestiture stranded costs of the TBD units of $1.084 million per month, as calculated by the Company in Schedule HAC-13 in the months following March 2003, the month in which the TBD units were assumed divested pursuant to the second (May 2002) auction. (RA-2 at 37-40; Schedule ACC-8). No credit was given for sales of excess energy and capacity

[28] As supplied by the Company by letter dated March 5, 2003 (Schedules HAC-1, 4, 5, 7, 8, and 9 of witness Chalks' testimony updated to reflect actual data through January 2003).

from the units, in that the requisite data was assertedly not supplied by the Company. (RA-2 at 39; RIB at 29). Additionally, and without quantifying this recommendation, effective August 1, 2003, witness Crane proposed reducing the 13.0% pre-tax return on the post-divestiture stranded costs of the TBD units allowed by the Final Restructuring Order to the "cost of debt found by the BPU and [the ALJ] to be reasonable." (*Id.* at 40).

In recommending that the above-market costs of the TBD fossil units be disallowed as of August 1, 2002, witness Crane contended that they became excess capacity as of that date by virtue of the Company having assumed they would be divested by then in arranging for its BGS supply for year four of the Transition Period (the year beginning August 1, 2002). On that assumption, ACE bid out 80% of its BGS requirement, the portion not obtainable from its NUGs, in the statewide auction conducted in February 2002.[29] To the extent the revenue requirement of the TBD units exceeded the revenue received from the sale of what she characterized as excess power, witness Crane argued that ratepayers "should not be forced to pay higher deferred costs simply because the Company miscalculated the amount of BGS supply that should be supplied through the auction." (*Id.* at 37-39).

<u>ACE's Rebuttal</u>

In rebuttal, Company witness Elliott recounted the history of the first auction and resultant sale of ACE's fossil units to NRG under an agreement executed on January 18, 2000 and filed with the Board for its approval on February 9, 2000. Filings for approval of the sale were also made with the Federal Energy Regulatory Commission ("FERC") and the Pennsylvania PUC ("PaPUC") at that time, both of which granted their approvals that same year. In New Jersey, however, BPU approval was delayed as a result of litigation that lasted for approximately two years. Without going into the merits of the arguments raised in this litigation the Company asserted that with a more timely decision, the "excess capacity" issue raised by witness Crane would have been avoided entirely. (P-8 at 20-23).

The contract for the Company's year four BGS supply was signed on February 15, 2002, on the assumption the sale would go forward. Following NRG's termination of the agreement to purchase the fossil units, ACE went to the PJM capacity market in an effort to sell the excess capacity. All such revenue, as well as the revenue received from energy sales were credited to BGS supply. Moreover, the Company asserted that the retention of the fossil units has been beneficial, because their operating costs are lower than, or in line with, alternative sources of supply on the open market. (*Id*.).

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[29] See *I/M/O The Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act,* <u>N.J.S.A</u> *48:3-49 et seq.,* Docket Nos. EX01050303, EO01100654, 655, 656 and 657, Orders dated December 11, 2001 and February 15, 2002.

NJLEUC's Position

NJLEUC contended that in deferring the difference between the revenue requirement of the TBD units (as well as the costs of ACE's NUG contracts) and BGS revenue, ACE was seeking to recover lost revenue, not true stranded costs. The distinction is significant, NJLEUC averred, because lost revenue could be recouped in the future, when charges for BGS could potentially be higher than they were during the Transition Period, thus obviating the need for any deferral recovery now. On the other hand, if shortfalls continued to be incurred, a base rate filing would be preferable to a "never-ending deferral mechanism." (NJLEUCIB at 29-32). NJLEUC additionally argued that the 13.0% pre-tax return (including an implied rate of return on equity of 12.4%) used in calculating the revenue requirement of the to-be-divested units was too high, and recommended that ACE's cost of long-term debt be used instead. (*Id*. at 33-34).

Staff's Position

Although Staff fully supported the Auditors' recommended review of B. L. England's costs, as discussed more fully below, Staff did not agree with the RPA's proposed disallowance of the above-market costs of the TBD units for the reasons set forth by the Company.[30]

As to the RPA's proposed reduction in the rate of return allowed on ACE's investment in the TBD units following the end of the Transition Period, Staff noted that the Board, after receiving comments on this issue as it pertained to B. L. England, planned to address the issue at its April 9, 2003 public meeting. Staff noted that the same result could be accomplished by a prompt securitization of B. L. England's stranded costs, and following the termination of the second auction of the fossil units in January, and with the encouragement of Staff, on January 31, 2003, the Company filed a petition with the Board seeking a determination of B. L. England's stranded costs eligible for recovery.[31] A second petition filed on February 14, 2003 requested the issuance of a bonded stranded cost rate order ("BSCRO") authorizing the Company to issue transition bonds to securitize the recovery-eligible B. L. England stranded costs determined by the Board.[32]

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[30] While agreeing that the retention of Keystone and Conemaugh throughout the Transition Period clearly benefited ratepayers, Staff did not agree that the same was true of B. L. England.

[31] Docket No. EO03020091*, I/M/O the Petition of Atlantic City Electric Company for an Administrative Determination of the Value of Certain Fossil Generation Assets*. As discussed more fully below, in addition to determining recovery-eligible B. L. England stranded costs of $149.5 million, net of tax, in its Order in this Docket dated September 25, 2003, effective April 21, 2003, the date the Company's rates were declared interim with respect to the return allowable on its investment in B. L. England by a Board Order issued on that date, the Board reduced the 13.0% pre-tax rate of return to 11.3%, reflecting a reduced rate of return on common equity of 9.75%, and further reduced the rate of return to an all-debt rate of 5.25%, effective August 1, 2003.

[32] Docket No.EF03020121*, I/M/O the Petition of Atlantic City Electric Company for a Bondable Stranded Costs Rate Order in Accordance with* N.J.S.A*. 48:3-49 et seq*. [remaining portion of caption omitted]. By Order in this Docket dated September 25, 2003, the Board authorized the Company to issue

By Order dated February 5, 2003 ("February 5, 2003 Order"),[33] the Board sought comments from ACE and the RPA as to whether the ratemaking treatment accorded B. L. England during the Transition Period should be prospectively modified, since it appeared that the plant had little, if any, current market value, and thus was unlikely to be divested in the near term, if at all, as envisioned in the Final Restructuring Order. The Board also questioned whether the 13.0% pre-tax return allowed on the plant investment could continue to be justified in view of the plant's high operating costs that were, at least in part, responsible for the lack of bidding interest that coal-fired capacity normally would be expected to attract. The all-in cost (capital and operating costs) of energy from B. L. England averaged approximately 9.4 cents per kwh during the year ended July 31, 2002, or about double the cost of the energy purchased for ACE's BGS supply pursuant to the Board-approved statewide auction held in February 2002. (February 5, 2003 Order at 3; Attachment B).

The February 5, 2003 Order listed a number of options for alternative ratemaking treatment. The first, amortization of the plant investment at an appropriate interest rate prior to its securitization as a stranded cost, mirrored the treatment accorded JCP&L's Oyster Creek nuclear unit. The second listed option would have reduced the return on the B. L. England investment to ACE's embedded cost of debt, or embedded cost of debt and preferred stock, or to these embedded costs plus a reduced rate of return on common equity, as compared to the 12.5% allowed in ACE's last rate case and reflected in the pre-tax return of 13.0%. The third listed option would have limited the amount paid by ratepayers for the plant's output to the cost of BGS supply. Lastly, the Order sought input on other possible options on the return issue. Comments were filed with the Board by the Company and the RPA on February 18, 2003. Pending further direction from the Board after considering these comments, Staff made no recommendation on the rate of return issue in this proceeding.

2. <u>Cash Working Capital, TBD Units</u>

<u>RPA's Position</u>

In recommending that the cash working capital ("CWC") and related return reflected in ACE's calculation of the TBD units' revenue requirement be disallowed, witness Crane asserted that ACE made no effort to validate the lead/lag days employed in the calculation, which were unchanged from those proposed in its last base rate case, and which were never explicitly ruled on by the Board, since that case was resolved via a Board-approved Stipulation. Moreover, she found the inclusion of depreciation expense as well as the omission of debt interest from the calculation to be inappropriate. As further reasons for disallowing ACE's CWC claim, she cited

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transition bonds of $152.0 million, including estimated capital reduction and upfront transaction costs of $2.5 million, for the recovery of B. L. England stranded costs. The bonds were subsequently issued (priced) at an average yield of 4.60% on December 16, 2003.

[33] In Docket Nos. EO97070455, EO97070456 and EO97070457, *I/M/O Atlantic City Electric Company Rate Unbundling, Stranded Cost and Restructuring Filings.*

the likelihood that the 13.0% pre-tax return allowed by the Final Restructuring Order exceeded ACE's actual cost of capital, as well as the additional compensation it received from the interest earned on the deferred balance during the Transition Period, which presumably would continue throughout the recovery period. (RA-2 at 34-37). In quantifying the proposed disallowance, witness Crane calculated the monthly return on the CWC determined by the Company at the same rate of return it employed in determining the revenue requirement of the TBD units, and "grossed up" the result to provide for income taxes. (*Id*. at 37, Schedule ACC-9).[34]

<u>The Company's Rebuttal</u>

Witness Morgan defended the Company's CWC calculation, asserting that to avoid the cost and complexity of performing a CWC study between rate cases, the most reliable information available is traditionally used. He asserted that depreciation expense should be reflected in the CWC calculation with zero lag to properly compensate investors for the reduction in rate base attributable to the depreciation reserve, and that by not reflecting any return, including the equity component in its calculation, the Company had taken a conservative approach. Even if valid, the deficiencies asserted by witness Crane did not justify disallowing the CWC claim in its entirety, or the 13.0% pre-tax return. (P-5 at 12-15). Witness Chalk also disputed the RPA's calculation of the reduction in the revenue requirement associated with the recommended CWC disallowance, maintaining that it failed to take interest synchronization into account. With interest synchronization reflected, the recommended disallowance would be reduced from approximately $5.7 million to $4.8 million. (P-13 at 6-8).[35]

<u>NJLEUC's Position</u>

NJLEUC also found the Company's calculation of cash working capital to be excessive, contending that the revenue lag assumed by ACE was too long, that the calculation did not reflect the lag in the payment of debt interest, and that it improperly included such non-cash items as depreciation and amortization. (NJLEUCIB at 32-33).

<u>Staff's Position</u>

Staff disagreed with the RPA's proposed CWC disallowance, and in particular, the RPA's treatment of depreciation expense and interest on debt. As to the lead/lag days issue, ACE utilized the lead/lag days from its last base rate case, filed in 1990. Witness Crane opposed using these lead/lag days, since there had been no attempt by ACE to verify that they were still valid. (RA-2 at 34). Company witness Morgan asserted that due to the cost and complexity of performing lead/lag studies in between rate cases, it is a traditional regulatory approach to use

[34] While Schedule ACC-9 includes the last year of the Transition Period, it was properly excluded from Schedule ACC-8, given the RPA's proposed disallowance of the above-market cost of the TBD fossil units as of August 1, 2002.

[35] At the February 21, 2003 hearing witness Crane agreed with Mr. Chalk on this issue. (Tr. 614). The RPA's revised (briefed) working capital disallowance was accordingly reduced to $3.793 million.

the most reliable information available. (P-5 at 12-13). Staff agreed with the Company that the lead/lag days from the last rate case could reasonably represent the lead/lag days during the Transition Period.

ACE included depreciation expense in its lead/lag study with a zero lag, arguing that this is appropriate because the total deprecation reserve is deducted from the plant in service balance in determining rate base, even though depreciation expense has not actually been collected from customers at the time the rate base is calculated. Including deprecation expense in the lead/lag study with a zero lag cures this mismatch. (*Id*. at 13). The RPA maintained that it was inappropriate to include deprecation expense because it does not result in cash outflows by the Company. The purpose of the lead/lag study is to determine the level of investor-supplied funds actually needed, not to compensate the Company for its expenses, as that compensation is included in other aspects of the deferral calculation. Therefore, only actual cash flows should be considered in determining ACE's need for a cash working capital allowance. (RA-2 at 35). Staff agreed with ACE, citing prior BPU decisions on this issue. In its Order dated April 6, 1987 in Docket No. ER85121163, *I/M/O Public Service Electric and Gas Company for an Increase in Rates*, the Board adopted the ALJ's recommended assignment of a zero lag to the Company's deprecation expense. This finding was reaffirmed by the Board in Docket No. WR00060362, *I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes,* by Order dated June 6, 2001.

RPA Witness Crane asserted that ACE should have included interest on debt in its cash working capital calculation, arguing that the Company has a contractual obligation to make these interest payments, which are generally made quarterly. Since ACE collects the funds needed to make such payments monthly, but generally pays interest expense quarterly, interest on debt provides a significant source of CWC. Ms. Crane maintained that this important source of cash working capital was ignored in ACE's calculation. (RA-2 at 36). In rebuttal, Mr. Morgan asserted that it is incorrect to single out for inclusion in a lead/lag study only the debt portion of the return on investment. The total return should be included with a zero lag since the return on investment is the property of investors when service is provided, as previously recognized by the BPU. In this case the Company assertedly took a conservative approach, in that it did not include any return on investment in the determination of the CWC associated with the TBD generation assets. (P-5 at 13-14). Staff agreed with ACE, noting that excluding interest on debt from the working capital calculation is consistent with prior BPU decisions. Staff also noted that the Company's determination of the revenue requirement of the TBD units included a consolidated tax savings adjustment that reduced the revenue requirement. Thus, the Company was consistent in its determination of the revenue requirement.

3. Restructuring/Consolidated TPS Billing Costs

RPA's Position

In recommending that ACE's claimed restructuring and consolidated TPS billing costs be disallowed, witness Crane contended that the Company had not met its burden of proof, and had improperly applied the 13.0% pre-tax return authorized by the Final Restructuring Order for accruing carrying costs on the unamortized balance of restructuring-related capital costs to the unamortized balance of deferred restructuring-related operating costs as well. (RA-2 at 41-44). Moreover, in her view, ongoing restructuring-related operating costs should be considered in the Company's base rate case. (*Id. at* 44-45).

<u>The Company's Rebuttal</u>

In rebuttal, Company witness Morgan supported the recoverability of ACE's restructuring-related, or transition costs as they were also referred to in the filing. (P-5 at 5-8). He reviewed and defended: 1) the amounts expended on the Customer Care System to implement the billing changes associated with the unbundling of the Company's rates ($8.994 million capitalized in the three years from 1997 through 1999, as shown on Schedule CFMR-3); 2) the costs incurred and capitalized in the year 2000 to develop the Balancing and Settlement System to track energy deliveries from third party suppliers ($0.284 million, as shown on Schedule CFMR-4); 3) regulatory restructuring-related O&M expenses incurred in the period from 1997 through June 2002, all of which have apparently been deferred ($7.792 million, as summarized in Schedule CFMR-5); 4) ongoing O&M expenses associated with the Customer Care System incurred during the period from 1999 through June 2002 and included in MTC recoverable costs as incurred ($3.675 million, as shown on Schedule CFMR-6); 5) ongoing O&M expenses associated with the Balancing and Settlement System incurred during the period from 1997 through June 2002 and included in MTC recoverable costs as incurred ($0.510 million, as shown in Schedule CFMR-7); and 6) $0.052 million of load profiling O&M expenses incurred and included in MTC recoverable costs in the year 2002 through June 2002 (Schedule CFM-8).

Of the capitalized Customer Care, Balancing and Settlement System costs, and deferred regulatory restructuring-related O&M expenses noted above, the amounts set forth in Schedules C and D of the Stipulation approved by the Final Restructuring Order ($4.323 million, $0.260 million and $6.566 million, respectively), were included as part of the costs recoverable by the MTC during the Transition Period, and in each case, on an eight-year amortization basis with carrying costs on the unamortized balances computed at the pre-tax rate of return of 13.0%. (P-11 at 11-12; Schedules HAC-6 and 7). The ongoing annual O&M expenses associated with the Customer Care System, the Balancing and Settlement System and load profiling (as summarized in Schedules CFMR-6, 7 and 8), were also claimed, as were ongoing annual "regulatory" operating costs. (Schedule HAC-7).[36]

<u>NJLEUC's Position</u>

NJLEUC maintained that absent a showing that ACE's current rates failed to compensate it for restructuring-related costs, they should be excluded from the MTC deferred balance, and that 50% of the $9 million of capital expenditures made on the Company's Customer Care System should also be disallowed in view of the system's asserted shortcomings, including its asserted inability to issue fully automated bills to ACE's largest customers. (NJLEUCIB at 35-38).

[36] Assumed included as part of the costs shown in CFMR-5.

Staff's Position

Staff agreed with the RPA that ACE had not met its burden of proof with respect to its claimed restructuring-related costs, in that it had not fully met the reasonableness and verification tests set forth in the Final Restructuring Order for the recovery of these costs. Staff agreed with the RPA that amortization over a period not to exceed eight years with a pre-tax return of 13.0% on the unamortized balance applied only to the capital portion of such costs, and additionally recommended that such amortization be calculated on a "net of tax" basis, as discussed below. Staff also agreed that ongoing post-transitional restructuring-related costs should be treated no differently than any other cost recoverable by base rates, *i.e.*, that going forward, these costs should be included in base rates without further deferrals.

Staff did not, however, propose an outright disallowance of ACE's restructuring-related costs, but instead that they not be included in establishing interim deferral recovery pending additional regulatory review in the Company's base rate case. This would allow such issues as the need for more detailed support, as contended by the RPA, the allocation between capital and O&M expenses, and the issue as to the possible extent to which non-incremental employee and other internal costs may have been included in the claimed restructuring costs, to be explored to a greater extent than was possible in this proceeding. Staff also found the Company's development costs associated with consolidated third party supplier billing (as shown on Schedule HACR-17 attached to P-13) to have been inadequately supported, and accordingly made the same recommendation with respect to these costs.

4. Auditors' Findings/Recommendations

The scope, objective and results of the Auditors' prudence review of ACE's procurement of energy and capacity needed for its BGS supply during the first three years of the Transition Period are set forth in Chapter VIII of the Audit Report. Among other audit tasks, the Auditors assessed the operating performance of ACE's generating plants devoted to BGS supply prior to divestiture, including B. L. England. Since the costs of the TBD plants are included in the costs recoverable by the MTC, if the plants operate poorly, the MTC deferred balance will increase. Conversely, good performance reduces the balance.

B. L. England's performance is discussed on pages VIII-39 to VIII-52 of the Audit Report. Based on measures commonly employed to assess plant performance (plant availability and capacity factors, forced outage rate, fuel and non-fuel operating costs), the Auditors found that B. L. England's performance had declined during the Transition Period, and was for the most part below industry averages, in some cases substantially so. In comparing B. L. England's production costs to those of four comparable plants, for example, the Auditors not only found them higher than the other plants, but that B. L. England was "the only plant whose costs have consistently increased throughout the seven-year period from 1994 to 2001." A chart included in this chapter indicated that in the year 2001, B. L. England's total production cost, at nearly 5 cents per kwh, ranged from approximately 60% percent higher than the next most expensive plant to over three times the cost of the least expensive plant. (Exhibit VIII-26).

The Auditors additionally found that this relatively poor plant performance, together with reserve shutdowns in some instances limited ACE's ability to respond to transmission congestion within its service territory. Congestion, in turn, increases the cost of power purchases. In 2001, for example, the number of hours in which congestion in the area served by B. L. England occurred increased by 1,100 hours over the preceding year, to 1,600 hours, during which the locational marginal prices ("LMPs") for power purchased from PJM frequently exceeded $130/Mwh, the cost of the most expensive combustion turbine on the PJM system, and during a few hours approached PJM's $1,000/Mwh bid cap.

Based on an analysis of the period June 23 through June 30 in each of the three years audited, the Auditors found that "the number of [B. L. England] outages during the examination period raises questions about the root of the outages and shutdowns. Questions also remain about the circumstances behind other congestion episodes and about the potential contribution of unused plant capability when power import limitations led to very high local prices." Accordingly, the Auditors recommended that a detailed review of ACE's operation and maintenance of B. L. England be performed "in light of the [plant's] cost and performance trends and impact of forced outages and reserve shutdowns on its use for congestion management." (AUD-2 at VIII-56). Staff accordingly recommended that this recommendation be included in the Initial Decision.

Finally, the Auditors found that $2.617 million of amortized deferred Gross Receipts and Franchise Taxes and Susquehanna deferrals had been incorrectly included as part of MTC-recoverable costs when they should have been included as part of regulatory asset recovery. (AUD-2 at I-5; V-8). Beyond this adjustment, which was agreed to by the Company, the Auditors proposed no disallowances of costs included in ACE's deferred MTC balance.

5. MTC Charge Effective August 1, 2003

In its Petition as filed, the Company sought an increase of $32.6 million in the MTC, consisting of deferral recovery of $43.397 million and a reduction in MTC charges for all other MTC-recoverable costs of $10.761 million, as shown in Schedule JFJ-7 attached to P-14.[37] The $10 million reduction as compared to the MTC then in effect was net of a proposed four-year amortization of the balance of deferred restructuring/transition-related capital and O&M costs not recovered during the Transition Period ($18.928 million less $4.172 million, or $14.756 million, as shown on Schedule JFJ-3 attached to P-14). The Company also proposed amortizing this amount with interest at 5.44%, the seven-year treasury rate plus 60 basis points applied to the deferred balances in the third year of the Transition Period (the year ended July

[37] With the exception of USF costs, in determining the rates per kwh to be effective August 1, 2003 for the recovery of costs recoverable by the MTC, NNC and SBC, the Company divided 10 months of costs by 10 months of sales (8,245 Gwh projected for the 10-month period from August 1, 2003 through May 31, 2004, from Schedule JFJ-8 attached to P-14). Although sales vary seasonally, this yields essentially the same rate per kwh as a determination based on 12 months of costs and sales. In determining the MTC charge for the recovery of costs other than the deferrals, however, a sales base of 8,784 Gwh was assumed. (P-14, Schedule JFJ-3). As noted, USF costs were proposed to be fully recovered over the 10-month period ended May 31, 2004. (P-14, Schedule JFJ-5).

31, 2002). (*Id.*). While the projected deferred MTC balance reflected the assumption that the fossil units would be divested in March 2003, and that a return on stranded costs of $1.084 million per month would be the revenue requirement of the TBD fossil units in the following months of April through July 2003 (Schedules HAC13/HACR-13 attached to P-11/P-13), in setting the MTC rate per kwh for the recovery of costs other than the deferrals, no revenue requirement associated with the TBD fossil units was assumed. (P-14 at 7-8) In the event a revenue requirement associated with the TBD units continued to be incurred after the Transition Period, the Company proposed that it be deferred and included as part of a true-up to the MTC rate effective June 1, 2004. (*Id*. at 8). While the adjustments to MTC recoverable costs proposed by the other parties would have an effect on the MTC charge per kwh, the effect of such adjustments was not quantified by the other parties.

C. <u>NNC DEFERRED BALANCE</u>

Atlantic's Net Non-Utility Generation Charge is a component of the MTC that recovers the above-market cost of power purchased under long-term power purchase agreements entered into with non-utility generators prior to restructuring. It also recovers "swap breakage" costs incurred in amending the PPA with the Keystone NUG (now Logan), as well as interest on the net of tax buyout costs incurred in buying out the PPA with the Pedricktown NUG, both as previously approved by the Board.[38] As set forth more fully in paragraph 23 on page 92 of the Final Restructuring Order, NUG purchases during the Transition Period could either be devoted to BGS supply and priced as set forth in paragraph 7 on page 87 of the Order (as discussed above in connection with the pricing of TBD generation when so used),[39] or sold in the competitive wholesale markets, *i.e.*, the energy and capacity markets administered by the Pennsylvania-New Jersey-Maryland Interconnection LLC ("PJM"), an Independent System Operator and the successor to the power pool of the same name. In each case, the amount included in the NNC is the difference between the amount paid under the PPA and the amount received from the sale of the NUG energy and capacity, or the value assigned to it when devoted to BGS supply.

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[38] The inclusion of Keystone swap breakage costs in the NNC was authorized by the Final Restructuring Order at 92, paragraph 23, as was the inclusion of interest costs associated with the buyout of the Pedricktown PPA. Paragraph 23 also required the savings in purchased power costs resulting from the buyout to be concurrently reflected in rates. Thus the Company implemented a 1% rate reduction on January 1, 2000, as described more fully in the Board's November 10, 1999 Order in Docket No. EE99090685, *I/M/O the Petition of Atlantic City Electric Company for Approval of an Agreement to Terminate its Power Purchase Agreement with Pedricktown Cogeneration Limited Partnership*. As noted s*upra*, the Pedricktown buyout interest was eliminated from the MTC upon the securitization of the Pedricktown buyout payment.

[39] When supplying BGS, the purchases can also be priced at PJM's capacity and locational marginal prices pursuant to paragraph 9 on page 87 of the Final Restructuring Order.

1. Heat Rate Dispute, Logan NUG

Company witness Chalk testified that as part of the costs recoverable by the NNC, ACE included costs incurred in an ongoing dispute with Logan Generating Company, L. P., the owner of a 200 Mw coal-fired NUG located in Gloucester County ("Logan"), over the facility's heat rate. As shown in Schedule HAC-5 attached to P-11, such costs amounted to $2.402 million through June 2002. An additional $0.067 million was expended in the months of July through December 2002, as shown in Schedule HACR-5 attached to P-13.

While noting that ACE believed it might ultimately recover approximately $3 million of alleged past overcharges it asserts resulted from the improper calculation of the facility's heat rate, RPA witness Crane recommended that the Logan litigation costs be eliminated from the NNC deferred balance and considered for recovery when the litigation is resolved and its net effect on ratepayers can be assessed. (RA-2 at 28-30). Although ACE claimed that it has spent over $2.4 million to date on the dispute, the RPA argued that the extent to which the costs incurred by the Company were prudent relative to its likely outcome remains unknown. Moreover, the Company is still expected to incur additional costs as a result of this litigation, and thus the ultimate benefits of the litigation remain unclear.

Staff concurred with the RPA's recommendation, as did Cogentrix, a part-owner of the Logan facility, who additionally argued that the costs attributed to the litigation by the Company were inadequately documented and supported.

In rebuttal, Company witness Elliot described the history of the Logan dispute and argued that "while a retrospective look at the actual outcome of the litigation should not be the standard applied, the fact that there was a successful outcome of that litigation certainly adds weight to a finding that it was a prudent action for the Company to take given what was known at the time the decision to enter into the litigation was made. These costs should not be disallowed." (P-8 at 23-25). Moreover, in its Initial Brief, ACE asserted that even witness Crane rejected the position that only successful litigation costs are recoverable. (CIB at 47).

2. Reporting Requirements

Asserting that there had been no mitigation of ACE's above-market NUG contract costs since June 2000, the RPA recommended that the Company be required to report its NUG mitigation activities to the Board annually, simultaneously with its annual NNC rate filings. (RA-2 at 31; RIB at 33). Staff supported this recommendation, and expanded it to include the filing of monthly data intended to allow the Board to monitor the degree to which NUG energy and capacity is being utilized to its best advantage on an ongoing basis.

While recognizing that it was too late to consider using NUG energy to displace this year's BGS supply obtained via the statewide auction (which Staff believed could provide greater value than the resale of the NUG energy to PJM), to determine whether pursuing such an option could be worthwhile, and to monitor and assess the value received from the resale of the NUG energy on an ongoing basis, Staff recommended that the Company be directed to file monthly reports with the Board showing, for each NUG project, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (whether it was resold in the wholesale market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rate, and finally, the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction.

3. Auditors' Findings/Recommendations

ACE's NUG cost mitigation efforts were reviewed in Chapter IX of the Audit Report. At the beginning of the Transition Period, ACE was party to PPAs with four projects aggregating 565 Mw of contract capacity. Of these, the PPA with the 106 Mw gas-fired Pedricktown project was bought out in November 1999, resulting in estimated net present value ("NPV") savings to ratepayers of $84 million over the 22 years then remaining of the initial 30-year term of the PPA. An amendment to the PPA with the 75 Mw municipal solid waste fueled DRMI/American Ref-Fuel project approved by the Board in December 2000 yielded additional estimated ratepayer savings of approximately $8 million.

At the time the Audit Report was prepared, negotiations had been underway with the remaining two NUGs, the 200 Mw coal-fired Logan and 184 Mw coal-fired Carney's Point facilities, but had stalled as a result of the heat rate dispute with Logan and ongoing financial difficulties of the 50% part owner of both facilities, National Energy Group ("NEG"), a subsidiary of Pacific Gas and Electric Company.

The Auditors found that the Company had complied with EDECA's requirement to demonstrate full market value for each of its NUGs, and with the advent of restructuring, had developed a reasonable and prudent program and approach to the mitigation of its NUG contract costs, which the Auditors found had been effectively implemented.

In Chapter IV (at 4) of the Audit Report, the Auditors found that in calculating interest associated with the buyout of the Pedricktown project, ACE had recorded the receipt of a $64 million tax refund one month later than the actual receipt date, and had the receipt been properly recorded, the buyout interest would have been reduced by $0.459 million, thereby reducing the NNC deferred balance by that amount, as indicated on page I-5 of the Audit Report. Both the RPA and Staff accordingly recommended that the NNC deferred balance be reduced by this amount.

4. NNC Charge Effective August 1, 2003

As calculated in Schedule JFJ-2 of P-14, with the revenue impact quantified in Schedule JFJ-7, the Company sought an increase of $40.115 million in its NNC charge, effective August 1, 2003, which was not challenged by any party.[40]

[40] On June 8, 2004, the Company petitioned the Board for a reduction in its NNC charge of $8.201 million and a $21.568 million increase in its SBC charges, for a net increase $13.367 million.

D. SBC DEFERRED BALANCE/CHARGES

Pursuant to N.J.S.A. 48:3-60, the SBC recovers costs incurred in implementing Board-approved programs intended to achieve specific public policy goals. The difference between the costs incurred by the Company and the related revenue received for the SBC components is included in the deferred SBC balance. During the Transition Period, the Company's SBC recovered costs associated with its previously-approved DSM programs and uncollectible accounts, as well as the pre-Transition Period amount allowed for funding the estimated cost of decommissioning its formerly owned nuclear units.

The Company proposed four changes to the SBC: 1) the addition of a component for the recovery of Universal Service Fund ("USF") costs incurred in implementing the Board's interim program established in 2002; 2) an adjustment to the DSM component to recover Comprehensive Resource Analysis ("CRA") program costs (now Clean Energy Program costs) on a prospective basis; 3) the addition of a component for the recovery of local and statewide Consumer Education Program ("CEP") costs incurred during the Transition Period, and 4) the elimination of the component for funding nuclear decommissioning ("ND") costs. The Company recommended that each of the SBC components be reset annually and be subject to deferred accounting and a true-up based on the prior period cost recovery. (P-14 at 3).

Based on actual data through December 2002, the Company projected that its SBC costs in the aggregate would be overrecovered by $21.109 million as of the end of the Transition Period. This net overrecovery reflected a projected ND overrecovery of $30.293 million ($30.293 million of decommissioning funding not matched by costs), underrecovered DSM costs of $1.386 million, and underrecovered UA expense of $7.798 million, all exclusive of interest. (P-13, Schedule HACR-14).

The SBC issues are discussed below:

1. Universal Service Fund ("USF")

In proposing to add this category of costs to the SBC, ACE sought to recover over the 10-month period from August 1, 2003 through May 31, 2004, $0.603 million of USF costs incurred and deferred in implementing the Board's interim USF program approved by its April 1, 2002 Order in Docket No. EX00020091.[41] These costs included bill credits of $200 granted Low Income Home Energy Assistance Program ("LIHEAP") customers in the year 2002[42] and related administrative costs, as well as carrying costs of $0.045 million calculated for the year 2002 and a portion of 2003. Additional interest at the rate of 5.44% (the seven-year treasury rate plus 60

[41] *I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999.*

[42] As indicated in the Company's response to S-CUSF-1, bill credits totaling $0.527 million were granted to 2,637 of ACE's low-income customers in 2002 under the Board's interim USF program.

basis points applicable to the deferred balances in the third year of the Transition Period) was proposed to be applied to the unamortized balance during the 10-month recovery period. (P-14 at 12-13; Schedule JFJ-5). ACE also proposed that the recovery of future USF expenditures be subject to deferred accounting and true-up.

The RPA recommended that the overrecovered SBC balance be applied to the year 2002 USF costs found to be recoverable, thereby eliminating the need to establish a USF charge effective August 1, 2003, and that the Board address the recovery of prospective USF costs separately. (RA-2 at 47).

Staff concurred with the RPA's recommendation to apply a portion of the overrecovered SBC balance to USF costs incurred in 2002, including interest, thereby eliminating the need to establish a USF charge effective August 1, 2003.

2. Clean Energy Program

In establishing a charge for the recovery of Clean Energy Program costs, or Comprehensive Resource Analysis costs as they were formerly known, ACE proposed recovering $9.529 million (the 10-month amount) of the $11.435 million of such costs authorized to be spent in the calendar year 2003 by the Board's Order in Docket Nos. EX99050347 *et al,* dated March 9, 2001 ("March 9, 2001 Order").[43] As was proposed for the other components of the Company's unbundled rates, the CRA costs would be recovered over the 10-month period ended May 31, 2004. (P-14 at 13-15). In accordance with the March 9, 2001 Order, the final balance (the projected July 31, 2003 balance) of anticipated overrecovered DSM costs was credited to the 10-month recovery by the Company. Although its DSM costs were projected to be underrecovered by $1.368 million based on actual data through December 2002 (P-13, Schedule HACR-14), a credit balance of $0.325 million was assumed in determining the CRA rate of 0.1118 cents per kwh derived in Schedule JFJ-6 attached to P-14. For CRA/Clean Energy Program costs incurred after 2003, ACE proposed that they be subject to deferred accounting with true-ups. (*Id*. at 14).

The RPA recommended that the DSM component of the SBC not be changed at this time, but addressed in a separate proceeding, and that the deferred July 31, 2003 DSM balance be included as part of the net overrecovered SBC balance the RPA proposed refunding to customers over one year. (RIB at 37; RA-2 at 47). The RPA also noted that the Auditors found that some of the Company's claimed DSM costs were recorded in the name of a Conectiv affiliate, and recommended that in the future, such costs be invoiced directly by the Company or otherwise documented to insure that the costs were in fact incurred by ACE. (RIB at 37).

Staff and NJLEUC did not propose any adjustments to the Company's claimed DSM/CRA costs or deferrals, nor oppose its proposed ratemaking treatment.

[43] *I/M/O the Petition of the Filings of the Comprehensive Resource Analysis of Energy Programs Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999*, Docket Nos. EX99050347, EO99050348, *et al*, GO99050352, *et al*.

3. Uncollectible Accounts ("UA")

ACE's accounting for uncollectible accounts requires the establishment of a monthly reserve, based on an assumed loss percentage applied to aged accounts receivable at month-end. The reserve is then compared to the actual pre-closing reserve, which is reduced by the month's write-offs and increased by write-off recoveries, and an adjustment is booked to bring the actual reserve to the required level. (AUD-2 at VI-2).

The Auditors found that as of July 31, 2002, the reserve for uncollectible accounts ("allowance for doubtful accounts") was $11.324 million, which exceeded by $1.417 million the required allowance of $9.907 million, and recommended reducing the deferred SBC balance by that amount (*i.e.*, reducing the underrecovered UA balance by $1.417 million, thereby increasing the net overrecovered SBC balance by the same amount). The Audit Report noted that ACE's management acknowledged that, based on the information available as of the date of the Audit Report, the allowance for doubtful accounts exceeded the required allowance. (*Id.* at VI-6). Staff and the RPA concurred with the Auditors' recommendation.

4. Consumer Education Program ("CEP")

The Company proposed adding a component to the SBC to recover CEP costs of $3.914 million over four years, including $3.376 million incurred and deferred during the first three years of the Transition Period, $0.026 million of additional costs projected to be incurred in year four of the Transition Period (subject to a Board finding that the measure of success standard had been met with respect to these costs), and accrued interest of $0.512 million. The Company also proposed accruing interest on the unamortized balance at the rate of 5.44% during the four-year recovery period. (P-14 at 11-12; Schedule JFJ-4).

By Order dated June 25, 1999, in Docket No. EX99040242,[44] the Board authorized the electric and gas utilities to defer expenses incurred in making consumers aware of the energy choice permitted by the recently-enacted EDECA, provided that Board-developed standards for measuring the success of these efforts were met. The CEP program was initiated on April 1, 1999, and was to end on March 31, 2002. The Board subsequently authorized additional expenditures for a fourth year, *i.e.*, through March 31, 2003, on a much more limited scale. (P-14 at 11-12).

The CEP was to be evaluated annually by an independent BPU consultant, the Center for Research and Public Policy ("CRPP"), to determine if the performance standards ("measures of success") established by the BPU were met. CRPP reports issued through March 31, 2001, found that the standards were met for the first two years of the program. Citing this, in petitions dated August 22, 2001 and January 31, 2002, ACE requested the recovery of CEP costs incurred in the first two years of the program. While no reports had been issued for year three (April 1, 2001 through March 31, 2002) or year four (April 1, 2002 through March 31, 2003),

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44 *I/M/O the Consumer Education Program on Electric Rate Discounts and Energy Competition.*

ACE additionally requested the recovery of expenditures made in these years in the instant filing. (*Id.*).

In auditing the Company's deferred balances, the Auditors noted that CEP and USF costs of $3.4 million and $0.6 million, respectively, had been separately deferred (not included in the SBC balance) as of July 31, 2002, and that the Company had proposed the recovery of all such costs incurred during the Transition Period in this proceeding. (AUD-2 at VI-7).

While the RPA presented no testimony on the issue, it argued extensively in its Initial Brief that even if it is assumed that the Company's CEP program met the performance standards established by the Board for the program, ACE had failed to demonstrate the reasonableness and prudence of its CEP costs, and thus that they should be disallowed. The RPA also contended that the assertedly misplaced focus of the program in years 2 and 3 rendered it largely ineffective in those years. In supporting its position, the RPA cited letters to the BPU dated January 11, 2001 and February 15, 2001 from its former Director expressing these concerns. (RIB at 40-47; Exhibits A and B).

With the exception of the interest rate, Staff found that the Company's CEP costs incurred through March 31, 2001, were consistent with the intent of the Board's consumer education initiative, and prudent. With respect to costs incurred from August 1, 2002 through March 31, 2003, Staff reserved its right to modify its position after reviewing the findings of the Phase II Audit Report as well as the CRPP reports covering the period from April 1, 2001 through March 31, 2003. Staff also recommended that the Company be directed to file a revised CEP rate each succeeding year to reflect, among other things, revised sales forecasts.

5. Nuclear Decommissioning Funding ("ND")

In the Company's last (1990/1991) base rate case,[45] the Board approved funding of $6.424 million per year to provide for the Company's share of the estimated cost of decommissioning the Salem, Peach Bottom and Hope Creek nuclear units in which it held ownership interests. In accordance with EDECA, this amount was included as part of the costs recoverable by the Company's SBC when its rates were unbundled on August 1, 1999. As noted *supra*, the Company's nuclear interests were subsequently sold to the co-owners holding the majority ownership interests in these units, and the sale was approved by the Board's Order in Docket No. EM99110870 dated July 21, 2000 ("July 21, 2000 Order"). Under the conditions of sale, the balances in the Company's decommissioning trusts established for the units were transferred to the purchasers on the sale closing date (October 18, 2001), and the Company's decommissioning funding obligation ceased as of that date. With respect to the funding still included in the SBC, the RPA recommended that it be eliminated, while the Company argued that the SBC charge should continue unchanged, thereby allowing the decommissioning

[45] Docket No. ER90091090J, *I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service*, Order dated July 3, 1991. The decommissioning funding level was approved on page 4.

component to potentially fund other programs that might be included in the SBC in the future. (July 21, 2000 Order at 23). In deciding the issue, the Board reasoned as follows:

> The Board notes that, in either case, the Company's overall rates would not change during the four year transition period and thus the revenues "freed up" by the cessation of decommissioning funding would either serve to reduce the SBC deferral if the SBC were left unchanged, or the Basic Generation Service, Net Non-Utility Generation Charge ("NNC") or Market Transition Charge ("MTC") deferral in the event the SBC were reduced. For that reason, we will allow the Company to maintain the SBC at its current level, recognizing that interest will be accrued on any over-recovered balance that may result, and that the full over-recovered balance with applicable interest shall be applied for the benefit of ratepayers in a manner to be determined by the Board at a future date…
>
> [*Id*.].

Until this filing, no other programs were or have been proposed for inclusion in the SBC, and thus, the ND component of the SBC deferred balance was projected to be an overrrecovery of $30.293 million as of the end of the Transition Period, based on actual data through December 2002. While no party opposed the Company's proposed elimination of ND funding from the SBC, which would yield a rate reduction of $7.3 million,[46] what to do with the net overrecovered SBC balance ($21.109 million after offsetting the ND overrecovery with the underrecovered DSM and UA balances) became an issue, as discussed below.

6. Dispostion of SBC Overrecovery

The Company proposed including the overrecovered SBC balance with the BGS, NNC and MTC deferred balances, and recovering the aggregate net balance over four years with interest at the seven-year treasury rate plus 60 basis points. (P-3 at 9-10; CIB at 50-51). After updating the SBC balance to reflect actual data through January 2003 and the Auditors' recommended UA disallowance, the RPA recommended that the resultant balance of $21.500 million first be used to offset USF costs incurred in the year 2002, and then refunded to customers over one year with interest. (RIB at 5; 47-48). Staff agreed with offsetting year 2002 USF costs with the balance, but contended that the method for returning the remaining balance to customers should not be addressed in isolation from ACE's base rate case proceeding, asserting that it was the Board's stated intent to look at all of the Company's unbundled rate components at the end of the Transition Period. Thus, Staff recommended that the issue of how to return this significant overrecovered balance to customers be moved into the base rate case proceeding. (SIB at 48-50).

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[46] As shown in Schedule JFJ-7 attached to P-14.

7. SBC Charges Effective August 1, 2003

As shown in Schedule JFJ-7 attached to P-14, if approved as filed, and based on the level of annual sales assumed by the Company in estimating the revenue effect of its proposed rate changes, the addition to the SBC of the component for the recovery of USF costs would yield an increase of $0.652 million, the addition of the component for the recovery of CEP costs an increase of $0.965 million, the change in the component for the recovery of DSM/Clean Energy Program (CRA) costs an increase of $4.502 million, and the elimination of decommissioning funding a decrease of $7.282 million.[47]

E. OTHER ISSUES

1. Interim Deferral Recovery

In its Initial Brief at 54, ACE stated that it was not seeking authorization to securitize its deferrals under the recently-enacted amendment to EDECA,[48] but rather a finding that "the recoverable deferred balance is eligible to be securitized. Then in a separate proceeding the merits of actually securitizing the deferred balance can be addressed." RPA witness Rothschild's understanding of this issue was similar: "I have been advised by Counsel that this proceeding is to determine what amount of the deferred energy balance was prudently incurred by the Company and the level of the prudently incurred deferred energy balance that is eligible for securitization. The Company may file a subsequent Petition with the Board to determine whether or not securitization is appropriate and in the ratepayer's best interest. Therefore, my primary focus in this testimony will be the appropriate amortization period and interest rate. Securitization data has been presented for comparison purposes only." (RA-18 at 7).

As noted above, by letter dated March 25, 2003 to the ALJs hearing the deferred balance cases of the four electric utilities, the Board recalled a number of issues related to the securitization and/or amortization of each utility's deferred balances. Specifically, the Board indicated that it was recalling:

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[47] On June 8, 2004, the Company petitioned the Board for approval to reset the USF and Uncollectible Accounts components of the SBC, and to eliminate the one-time credit the Company was directed to implement below. If approved by the Board, the SBC changes in the aggregate would result in an increase of $21.568 million or a net increase of $13.367 million after reflecting a proposed reduction in the NNC of $8.201 million.

[48] Senate Bill 869 signed into law by Governor McGreevey on September 6, 2002. In addition to the two categories of stranded costs previously allowed to be securitized under the EDECA (generation-related stranded costs, or the amount by which the net cost of a generating asset exceeds its market value, and buyouts and buydowns of above-market power purchase agreements with non-utility generators), this legislation established a third category of securitizable costs, "basic generation service transition costs."

> …the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized, and for those balances to be amortized, what is the appropriate length of the amortization and the interest rate. In addition, the Board is recalling the issue of whether all or part of the prudently incurred deferred balances are legally eligible for securitization under EDECA. The individual Administrative Law Judges should be making findings as to what the level of prudently incurred deferred balances is for each utility.
>
> The Board will be making findings as to the appropriate transitional amortization and interest rate for such deferred balances between August 1, 2003, until such time as a final Board decision is made on the issue of securitization v. amortization and any authorized transition bonds are issued. To the extent that the parties have offered opinions on the setting of transitional amortization and interest rates in their cases, those portions of their briefs will be reserved to the Board and decided by the Board as part of their final rate Order. The issues that are being recalled will be considered by the Board in the individual securitization petitions filed by the individual utilities. To date, only two utilities, Rockland Electric Company and JCP&L, have made such filings with the Board. Individual procedural schedules will be set for each of the securitization proceedings.
>
> [March 25, 2003 Secretary's Letter at 1-2].

Pending the filing of a securitization petition, ACE proposed that all of its deferred balances be amortized over four years, with interest on the unamortized balance accrued at the rate approved by the Board for interest accruals on the deferred balances during the Transition Period (the yield on constant maturity seven-year treasury notes plus 60 basis points, adjusted annually to reflect the yield shown in the Federal Reserve Statistical Release on or closest to August 1st of each year). (P-3 at 9-10). With the exception of the SBC balance, and in lieu of securitization, the RPA proposed that the balances be recovered over 10 years, with interest on the unamortized balance also accrued at the seven-year treasury rate plus 60 basis points, but fixed as of the date amortization begins. (RA-2 at 46-47; RA-18 at 3-6; 17). NJLEUC also proposed a 10-year amortization with interest at the 10-year treasury rate plus 60 basis points. (NJLEUCIB at 39-41).

Based on the aggregate BGS, NNC, MTC and SBC balance of $176.8 million projected as of the end of the Transition Period in the initial filing[49] and an assumed interest rate of 5.44% (the

[49] As set forth in witness Janocha's Direct Testimony (P-14 at 3; Schedule JFJ-1). The slight difference between this and the balance elsewhere in the initial filing ($176.4 million) appears to be due to

seven-year treasury rate plus 60 basis points applied to the deferred balances in the third year of the Transition Period), the deferral recovery proposed by the Company would be $49.4 million per year.[50] (P-14, Schedule JFJ-1). Employing the same deferred balance for illustrative purposes only, and assuming an interest rate of 4.31% and amortization of the balance net of tax over 10 years, the RPA's witness Rothschild calculated deferral recovery of $21.462 million per year.[51]

During the period from August 1, 2003 until the date of securitization closing, or such other date on which amortization in lieu of, or in combination with securitization of the Company's deferred balance begins, as determined by the Board, Staff recommended that the Company's aggregate BGS, NNC and MTC deferred balance also be recovered over 10 years, and in view of the short period in which the proposed interim recovery was expected to be in effect, Staff additionally recommended that the seven-year treasury rate plus 60 basis points be reduced to the yield on constant maturity one-year treasury notes plus 30 basis points, or to 1.6%, based on the yields reported in the Federal Reserve Statistical Release dated March 3, 2003.[52] Staff also proposed that the amortization be determined net of tax, as illustrated in Appendix SIB-1 Attached to Staff's Initial Brief. (SRB at 4).

Applying this recommendation to an updated estimate of the Company's projected aggregate BGS, NNC and MTC deferred balance[53] reduced by Staff's recommended adjustments ($131.731 million, as summarized in Appendix SRB-1 attached to Staff's Reply Brief) yielded interim deferral recovery of $13.868 million per year, or 0.160 cents per kwh, based on the annual sales assumed by the Company in estimating the effect on revenue of the rate changes proposed in the filing (8,682 Gwh, from Schedule JFJ-7 attached to P-14). (SRB at 4).

2. <u>Interest Calculation</u>

RPA witnesses Crane and Rothschild recommended that ACE's interest accruals, including accruals during the Transition Period, be calculated net of tax, *i.e.*, that accumulated deferred

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the application of the projected July 31, 2003 DSM deferred balance to initial CRA recovery, as shown in Schedule JFJ-6 attached to P-14.

50 When applied to the sales base assumed in estimating the revenue effect of the rate changes sought in the filing (8,682 Gwh), the deferral recovery rate per kwh determined in Schedule JFJ-1 yielded annual recovery of $43.4 million, as shown in Schedule JFJ-7 attached to P-14.

51 $0.002603 per kwh times 8,244.911 Gwh from Schedule JAR-1 attached to RA-18.

52 Use of the short-term debt rate is also consistent with how the deferred balances were financed during the Transition Period, *i.e.*, with short-term debt, as stated by the Company in response to S-CSEC-14 (Exhibit S-5).

53 Based on actual data through January 2003, distributed to the parties by letter dated March 5, 2003, and forecast data included in witness Chalk's Rebuttal Testimony (P-13, Schedule HACR-10).

income taxes be deducted from the balance of the deferred costs on which interest is accrued in recognition of the fact that when incurred, the deferred costs produced a tax benefit equal to 40.85%[54] of the deferred costs. The RPA's witnesses asserted that such treatment is appropriate and consistent with recent Board policy.[55] (RA-2 at 25-26; RA-18 at 15-16; RIB at 53-54).

In opposing net of tax interest accruals, the Company cited the interest calculation methodology employed with the discontinued LEAC. Citing N.J.A.C. 14:3–13.4(c), the Company argued that this regulation specifies that interest should be accrued on the cumulative deferred balance, not the balance net of tax. Nor does the Final Restructuring Order explicitly state that interest was to be accrued on the net of tax deferred balances during the Transition Period. In the Company's view, if the Board had intended net of tax treatment it would have said so. (P-13 at 5-6; CIB at 43-46).

While agreeing that the Final Restructuring Order does not explicitly state that deferred taxes should be deducted from ACE's deferred balances for the purposes of accruing interest, Staff contended that such a deduction is permissible and appropriate, especially in view of the lack of uniformity on this issue among the four utilities.[56] While in retrospect, Staff averred, the restructuring orders could have been more precise on what basically is an implementation detail, this should not preclude review of the issue on its merits. As to ACE's argument citing the interest calculation methodology employed with the discontinued LEAC, Staff noted that the relevant language in the Final Restructuring Order refers solely to the rate recovery mechanism, and is silent both with respect to the interest rate to be used (which is defined elsewhere in the Order) and the balance to which it is to be applied. (SRB at 6).

In maintaining that net of tax treatment is consistent with sound regulatory practice, Staff asserted that no party contended that the deferred taxes associated with the deferred balances should not be accorded the same treatment deferred taxes receive in base rate proceedings,

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[54] The composite federal income tax rate (35%) and New Jersey Corporation Business Tax ("CBT") rate (9%), with state taxes deductible from income in computing federal taxes.

[55] As evidenced by the Board's Order issued on October 16, 2002, denying, with respect to the net of tax issue, RECO's Motion for Reconsideration filed in response to the Board's Final Order issued on July 22, 2002 in RECO's restructuring proceedings, *I/M/O Rockland Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings*, Docket Nos. EO97070464, EO97070465 and EO97070466.

[56] Interest on JCP&L's deferred balances during the Transition Period was accrued net of tax, as was RECO's pursuant to the October 16, 2002 Order noted *supra*. Although interest was originally accrued on the gross balance by PSE&G, as part of the June 6, 2003 Settlement approved by the Board in PSE&G's deferred balances proceeding (*I/M/O the Petition of Public Service Electric and Company's Deferral Filing Including Proposals for Changes in its Rates for its Non-Utility Transition Charge (NTC) and its Societal Benefits Charge (SBC) for the Post Transition Period Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, Docket Nos. ER02080604, et al)*, PSE&G agreed to net of tax accruals on its NTC and SBC deferred balances during the Transition Period (Order dated April 22, 2004 at 16, paragraph f).

namely deduction from rate base, and for the same reason: because they represent "cost free" capital supplied by the IRS and the State Treasury on which no return is due, either when the tax benefit is received, or during the period when the taxes are "paid back" as part of the recovery of the related deferred costs. (*Id*. at 6-7).

Staff additionally asserted that the Board has been moving in the direction of standardizing the treatment of interest accruals in all instances where tax benefits effectively reduce financing costs, as evidenced by the discussion in the October 16, 2002 RECO Order *supra.,* in which the Board noted that interest on the unamortized balance of RECO's NUG buyout payments was to be accrued net of tax. Similarly, all securitizations of stranded costs approved by the Board to date have been structured on a net of tax basis. When approved for accrual on the unamortized balance of PSE&G's Remediation Adjustment Clause ("RAC") costs, carrying costs were also to be determined by applying the interest rate to the net of tax balance. (*Id*. at 7).

Staff accordingly supported the RPA on the net of tax issue, and additionally recommended that going forward, interest on "new" deferrals also be accrued net of tax, both with respect to the deferred costs and the deferred interest, which like the deferred costs also provides a tax benefit when incurred. Consistent with its recommendation in RECO's deferred balance proceeding,[57] Staff recommended that ACE's actual average cost of short term debt (debt maturing in less than one year) be employed as the interest rate, or in the event the Company has no short-term debt outstanding, that the rate available on temporary cash investments be used. Finally, as noted above, Staff recommended that the aggregate BGS, NNC and MTC balance be amortized net of tax. (*Id*.).

While the Advocate and the Company addressed the net of tax issue in their testimony and Briefs, neither party proposed or took a position on the interest rate and calculation methodology to be applied to post-Transition Period deferrals.

F. <u>RATE DESIGN</u>

ACE proposed recovering its deferred balances through an energy-only rate applied to all kwh sales uniformly across all customer rate schedules. (P-14 at 4; Schedule JFJ-1). Under its proposal this "Deferred Balance Recovery Rate" would be included as a component of the MTC. (*Id*. at 4). Effective August 1, 2003, the MTC would also include a component to recover the amortization of deferred restructuring-related capital and O&M costs, including: 1) costs incurred in modifying ACE's Customer Care System; 2) the cost of installing a system to allow for the balancing and settlement of hourly requirements within ACE's PJM zone; 3) expenses associated with restructuring-related regulatory proceedings; and 4) to the extent not recovered by fees, costs related to the development, implementation and management of a process to coordinate the relationship with third party suppliers over the Transition Period. The MTC would also recover any ongoing O&M expenses related to the continued implementation of retail

[57] *I/M/O The Verified Petition of Rockland Electric Company for the Recovery of its Deferred Balances and the Establishment of Non-Delivery Rates Effective August 1, 2003*, BPU Docket No. ER02080614, Staff's Initial Brief at 32-33.

choice and restructuring. The final MTC rate would include both the restructuring-related component and the deferral recovery rate, plus the 6% New Jersey Sales and Use Tax and the BPU assessment levied pursuant to N.J.S.A. 48:2-60. The Company also proposed that the MTC continue to be subject to deferred accounting treatment, and that the MTC rate be reset and trued-up annually based on the prior period cost recovery. (*Id.* at 6).

Both Staff and the RPA supported the energy only aspect of the Company's proposal, the RPA provisionally, pending addressing the issue further in the Company's pending base rate case.

NJLEUC opposed ACE's proposal, asserting that it would result in high load factor customers bearing a greater share of MTC costs than they would under the previous MTC rate structure, which for the MGS Secondary, MGS Primary, AGS Secondary, AGS Primary and TGS rate schedules included a demand component. (NJLEUC-1 at 5-6, Tr. at 551). NJLEUC accordingly recommended that this demand and energy rate structure be retained.

NJLEUC further proposed that ACE's MTC and NNC rates be adjusted by applying differing loss factors for customers served at transmission and primary voltage levels. (*Id*. at 3-5). Witness Gorman testified that customers taking service at higher voltage levels experience fewer line losses, thus ACE incurs higher generation and purchased power costs to serve secondary voltage customers as compared to customers taking service at transmission voltage. (*Id*. at 4) Mr. Gorman also contended that the elimination of loss factors would result in shifting costs to higher-use customers, and that loss adjustments have historically been used to reflect the differing costs associated with the differing voltage levels at which service is taken.

Staff agreed with NJLEUC's recommended retention of line loss factors in billing the MTC and NNC. The Company did not object to the proposal, and agreed to modify these rates accordingly, provided no other party objected. (CIB at 55-56).

IV. INITIAL DECISION ("I.D.")

On June 2, 2003, ALJ Sukovich filed her Initial Decision with the Board. The Decision included a procedural history, a summary of ACE's Petition, and a discussion of the regulatory context in which the Petition was to be considered, including the post-restructuring environment ushered in by the passage of EDECA in February 1999. Her findings on the issues in dispute are discussed below.

A. BGS DEFERRED BALANCE

1. Standard of Review

In considering the prudence of ACE's BGS procurement, the ALJ first set forth the relevant regulatory requirements ("burden of proof") that must be met when a utility seeks a rate increase:

> It is axiomatic that a public utility seeking a rate increase has the burden to prove the reasonableness of the increase sought…To be reflected in rates, utility expenses must by justified…A utility must bear the burden not only of proving the amount of operating and other expenses, but also of proving the basis of charges to its expense accounts and the propriety of including such charges for ratemaking purposes…A utility has a burden to show that amounts charged to operating expenses are not excessive… There must be sufficient, relevant evidence to support findings of fact and the reasonableness of rates established…In determining just and reasonable rates, the BPU may not rely solely on the books of a utility, but must go behind the figures shown by the company's books. There must be sufficient proof not only as to the amounts in the accounts, but also as to the reasonableness of the accounts…The party with the burden of proof in an administrative hearing must prove its case by a preponderance of the believable evidence.
>
> [I.D. at 59-60, citations omitted].

The ALJ then set forth the criteria for evaluating the reasonableness of ACE's BGS procurement:

> All parties, and the Auditors, recognize that the standard for determining if there should be any disallowance is whether petitioner's procurement practices were reasonable at the time in question, given the facts known, or that should have been known, to the Company at that time, not a hindsight approach. Such is consistent with the principle that ratemaking is prospective in nature. *Petition of Elizabethtown Water Co.*, 107 *N.J.* 440 (1987). EDECA also sets forth a reasonableness, as well as a prudency, standard pertinent to recovery of costs in the context of deregulation. As discussed hereinabove, the concept of reasonableness is reflected in both N.J.S.A. 48:2-21, EDECA, and the *Final Order*. Pursuant to the *Final Order*, the Company must also have tried to mitigate risks. Although petitioner may have shown why BGS procurement costs were incurred, *i.e.*, efforts to obtain supply, such does not answer the question of whether its efforts were reasonable. Whether or not benefits were derived is not the only test, but whether actions taken were reasonable at the time in question. As part of the analysis, as Ratepayer Advocate argues, is whether petitioner sufficiently mitigated risk.
>
> [*Id.* at 60].

With respect to whether a distinction should be made between "reasonableness" and "prudency," and whether ACE's actions during the Transition Period met the test set for either, the ALJ observed as follows:

> The parties do not address whether there are differences between the concepts of "reasonableness" and "prudency," and based on the testimony of the Auditors, and the analyses of all parties, for purposes of this proceeding, I am persuaded that any differences are not material, although imprudence arguably denotes connotations other than unreasonableness. *Black's Law Dictionary* defines "reasonable" as fair, proper, just, moderate, and suitable under the circumstances. "Prudent" is defined as sagacious and adapting, circumspect, practically wise, judicious, careful, discreet, circumspect, and sensible. *Black's Law Dictionary* 1138 (5 Edition 1979). There may, in given circumstances, be more than one action or omission that is reasonable. Imprudent, in contrast, may connote an action or omission not reasonable in any respect and may almost indicate negligence. In the current matter, any such distinctions are not material. As referenced, ratemaking principles traditionally reflect a reasonable standard, and EDECA and the *Final Order* require that actions or costs be both reasonable and prudent. Based on the record, I am persuaded that no actions or omissions of petitioner constitute imprudence, but some were not reasonable.
>
> [*Id*. at 61].

2. BGS Procurement Performance

In reviewing ACE's BGS procurement performance over the first three years of the Transition Period, the ALJ noted that while the parties had not identified any single decision as being unreasonable, the reasonableness of the Company's actions should be considered over the period as a whole:

> Petitioner, in part, argues that…no party points to any discrete decisions which were unreasonable, given the circumstances at the time. Such an approach, however, ignores the record as a whole and is inconsistent with the principle that the burden of proof is on the Company. I am persuaded by the argument of NJLEUC that the entire period must be viewed as a whole and by Crane's testimony in that regard. (Tr., pp. 618-619 & 713-715). If a particular decision were unreasonable, subsequent decisions, in the context, may be deemed to be prudent. However, such an approach can result in ratepayers bearing costs which were the result of imprudent determinations. A more reasonable approach,

> in my view, is to consider whether the Company's procurement procedures and processes throughout the entire Transition Period were reasonable based on the information available at the time in question.
>
> [*Id*. at 61-62].

The ALJ then identified problems that were present from the outset:

> A review of the record as a whole supports a conclusion that, for whatever reasons, petitioner did not initially take steps that would have been reasonable at the time to gain better control over the entire procurement process. The record contains no persuasive rationale for petitioner's failure to initially assemble an experienced BGS supply organization, in terms of both personnel and research. Compounding the situation was the fact that the staff assigned to energy procurement were not performing such functions on a full-time basis. Such was especially important in light of the fact that there was uncertainty regarding competition, PJM rules and markets, the level of BGS customers, over time, and the timing of divestiture. As the Auditors testified, reasonable and prudent management would have been to assure that the decision-makers were the most qualified to make important supply decisions, especially given the uncertainty at the time in question and the new environment of deregulation *per se*.
>
> [*Id*. at 62].

These uncertainties in turn suggested that it would have been more reasonable for ACE to have sought more supply options vis-à-vis contracts than a full requirements contract:

> Those uncertainties were testified to by ACE's witnesses, and the Company offered them, in part, as a rationale for seeking to obtain a full requirements contract. As NJLEUC argues, however, because of such uncertainty, it would have been more reasonable for petitioner to seek more supply options vis-à-vis contracts, and it was unrealistic, at the time, to expect that other suppliers, given the uncertainties, would have bid for a full supply contract. The *Final Order* gave clear notice that petitioner should take steps to attempt to mitigate the risks associated with uncertainty. ACE personnel recognized, as reflected in the above findings of fact, that it was entering a new field, procurement of an energy supplier, with a short lead time.
>
> [*Id.*].

Nor did the ALJ find that the Company had appropriately considered the other supply options envisioned by the Final Restructuring Order:

> Although there was an emphasis on the RFP process in the *Final Order,* the BPU clearly gave notice that other mechanisms should be considered, such as parting contracts and the sale of assets, as well as a preference for 12-month contracts. Arguably, the BPU viewed reliance on the spot market as an interim measure. Such was especially so in light of ACE's stated intention to divest generating assets. There is scant evidence in the record of consideration by petitioner of parting contracts or other financial instruments for hedging purposes. The fact that petitioner did not conduct any hedging option studies subsequent to that of June 2000, although prices were increasing, and the BPU had indicated that above-market costs reasonably entered into could be passed through to ratepayers, also lends credence to intervenors' and Staff's positions. Not only did petitioner fail to explain why parting contracts were not considered, the record does not evidence why its affiliated service company was not utilized.
>
> [*Id*. at 63].

The ALJ also cited ACE's failure to comply with the Board's directives as evidence of the Company's failure to effectively manage the procurement process:

> ACE also failed to submit an RFP plan to the BPU by the mandated September 15, 1999 date. The record is devoid of evidence that it advised the BPU, at that time, of the reasons for the failure to do so. Petitioner's argument that it should not be penalized for that omission has some merit. The current matter is not a disciplinary one. However, petitioner's failure to comply with the BPU's directive, and to advise the BPU of the reasons at the time, reflect some failure to effectively manage the procurement process. As Ratepayer Advocate argues, a reasonable and prudent management will comply with mandates established by the relevant regulatory authority. Although it was not a mandated deadline, petitioner's actions also did not maximize the probability that it would enter into a contract for BGS supply by December 15, 1999, as reflected in the *Final Order.*
>
> [*Id.*].

Moreover, even if it were impossible to establish a clear nexus between ACE's failure to meet the September 1999 deadline and the costs the RPA seeks to disallow, it is incumbent on the Company to demonstrate that its procurement practices, overall, were reasonable:

> Although, as petitioner argues, there is no clear nexus in the record to show that its failure to file for RFP approval in September 1999 had a direct relationship to any costs Ratepayer Advocate seeks to disallow, the point of the analysis of intervenor, and the other parties, is that it is incumbent on petitioner to show that its procurement practices, overall, were reasonable, not for other parties to establish a direct causation link, which may be impossible.
>
> [*Id*. at 63-64].

3. Third Party Purchases, July-August 2001

The ALJ noted that the RPA's recommended disallowance of the excess cost of third party purchases during July and August 2001 was quantified by limiting the allowable cost of the purchases to the average cost of ACE's TBD generation and NUG power in those months, or to $73.66 per Mwh in July and $70.50 per Mwh in August, resulting in reductions in the BGS deferred balance reductions of $12.821 million and $12.706 million in these months, respectively. (*Id*. at 50).

The ALJ did not find the RPA's calculation of any adjustment persuasive "in light of the fact that the BPU apparently approved the portfolio approach [RFP IV for the purchase of energy in these months]." (*Id*. at 69). On the other hand, she did find the rebuttal testimony of Company witness Elliott on the quantification of the adjustment to be persuasive:

> As [Elliott] noted, a "significant" portion of the cost of generation is the result of imbedded capital "invested long ago" under different market conditions and the costs of the NUG contracts were a result of agreements signed at different times, under different "rules." (Exh. P-8, p. 12.). Additionally, Elliott testified that the "high" market prices during the summer reflected the value of energy and the expected price that producers wanted for their products in 2001 and other producers were willing to pay. It is not clear that ACE could have found willing buyers at lower than market prices. Elliott noted that cost-based pricing had "disappeared" by 1999. *(Ibid.)* Additionally, as petitioner argues, it is not entirely clear if Crane compared base or intermediate load costs to peak period costs. Elliott testified that energy from NUGs is produced "virtually" daily throughout the year, and petitioner's TBD generation also produces energy "year round" as intermediate or base load units. However, the RFP 3 and RFP 4

> contracts were entered into for on-high peak summer energy. Elliott noted that "Peak power summer costs are always going to be higher than average annual costs…." (*Id*. at 13.) Crane performed no analysis of any materials regarding energy prices, other than noting the differences in summer prices. She relied on no specific publications and had no knowledge of any long-term contracts signed by any utility in the PJM region during 1999-2001, nor prices associated therewith in effect during 2001 and 2002.
>
> [*Id*. at 69].

On the basis that the relevant facts were not sufficiently detailed in the record, the ALJ was not persuaded by Staff's analysis comparing costs incurred by petitioner, JCP&L and RECO. The ALJ rejected Staff's PJM benchmark for the same reason:

> Staff's analysis in its initial brief comparing costs under petitioner's contracts for BGS supply to the costs to purchase from PJM without a contract was not subject to cross-examination. In fact, this judge denied a discovery motion made on behalf of Staff, for the first time, on the first day of hearings, Staff indicating that it was requesting the information because the Auditors had not done such an analysis. The appropriate way for such to have been presented was for Staff to either present witnesses or develop such through cross-examination of other parties' witnesses, not an approach which circumvents denial of a discovery request. In addition, petitioner raises meritorious concerns regarding Staff's analysis, on its face, which is based on the assumption of large amounts of BGS supply purchased at available PJM rates in a market that would not have been affected by large-scale purchases. Additionally, the analysis also apparently utilized price data outside ACE's zone in PJM. Without going into detail, petitioner presented an analysis indicating that any such differences would have been smaller that that calculated by Staff, which calculations approximate, in number, ultimately, Ratepayer Advocate's adjustment.
>
> [*Id*. at 67-68].

Accordingly, the ALJ rejected the recommended disallowance of $25.527 million of the cost of the July and August 2001 third party purchases deemed excessive by the RPA. (*Id*. at 73).

4. Excess Capacity Purchases

Similarly, the ALJ rejected the RPA's proposed excess capacity adjustment of $3.375 million, finding that the RPA's witness Crane failed to distinguish between long and short term contracts, or stated another way, that her methodology relied on "an inferred theory that if revenues received in a particular month for a capacity sale did not cover the capacity expenses incurred in a month for an equivalent amount of capacity bought, there should be a disallowance." This asserted shortcoming in her methodology accordingly produced such anomalies as calculating disallowances in months when profitable capacity sales actually occurred (January, February and March 2002). Moreover, the ALJ found that: "[no] part of her analysis was based upon a conclusion that the costs in questions were not actually incurred, that petitioner did not actually credit the revenues it received from selling capacity, or that ACE should have sold more, or less, than it did. Nor was Crane's adjustment in any respect based upon a conclusion that petitioner should have sold capacity at different times than it did, that the capacity was purchased at prices that were not consistent with market conditions, that any of the costs were "imprudently incurred", or that those costs are recovered in other elements of petitioner's charges." (*Id.* at 70-71).

While rejecting the RPA's excess capacity adjustment, the ALJ was persuaded by the Auditors' analysis, and accepted their recommended disallowance of $6.100 million for ACE's failure to take the full 400 Mw of capacity offered in response to RFP III. (*Id*. at 71-73).

5. BGS Administrative Costs

After reviewing the level and the purposes of ACE's claimed BGS administrative costs, and although noting that $1.398 million of "merchant support costs" included in these costs had not been specifically authorized by a Board Order,[58] the ALJ concluded that all such costs should be reflected in the BGS deferral, and that the RPA's proposed $3.528 million adjustment should be rejected. (*Id*. at 73-76). In support of this conclusion the ALJ found that:

> . . .EDECA envisions that costs incurred to provide BGS, including administrative costs, shall be recovered in rates. *N.J.S.A*. 48:3-57a&e. The Company presented sufficient evidence regarding the amounts and types of expenses included in BGS administrative costs to warrant recovery. There is no other mechanism for recovery of such costs, other than via the BGS deferral, and such costs are not currently included in rates, especially in light of the fact that petitioner's last rates were effective some eight years prior to the effective date of EDECA. Crane testified on cross-examination that she did not identify any supply procurement related expenses still reflected in T&D rates subsequent to August

58 As noted by the Auditors in the Audit Report at III-5.

> 1999. (Tr., p. 761). She did not dispute that the costs were actually incurred by petitioner. (*Id.* at 769).
>
> Ratepayer Advocate's argument, as also reflected in Crane's testimony, that those "types" of costs are reflected in rates set years before unbundling and a competitive structure were implemented is patently without merit. Intervenor also mischaracterizes the conclusions of the Auditors, which did not recommend an adjustment. Additionally, the testimony of various Auditors regarding whether RFPs 1, 2, and 3 were "unreasonable" as opposed to "flawed", was conflicting. Although there were "flaws" in the RFP 1, 2, and 3 procedures, such does not, in my judgment, justify a disallowance of all administrative costs incurred in providing BGS service.
>
> [*Id*. at 76].

6. LEAC Interest

Finding the testimony of Company witness Chalk persuasive on this issue, and that ACE's practice was consistent with pertinent BPU regulations (N.J.A.C. 14:3-13.4(a)- (f)), the ALJ denied the $1.993 million interest adjustment proposed by the RPA.[59] While noting that a LEAC cost adjustment was typically to be effective for a 12-month period, the ALJ observed that it could be otherwise if specified in an appropriate rate proceeding. In that the statute called for the interest calculation to be made over the "clause period," the Company's determination of interest as of the end of the time period covered by its last LEAC was found to be consistent with the pertinent regulation. (*Id*. at 16-20).

B. MTC DEFERRED BALANCE

1. Above-Market Costs of TBD Fossil Units

In rejecting the RPA's proposed disallowance of the above-market costs of the TBD fossil units in excess of carrying costs on imputed stranded costs in Year 4 of the Transition Period, the ALJ found that the excess capacity argument on which the RPA's recommendation was based was largely related to the failed NRG sale, which the ALJ did not attribute to the unreasonableness of the Company. While contending that ratepayers would pay higher rates to the extent the revenue requirement of the TBD units exceeded the revenue received from the sale of the excess power, the RPA's witness "did not calculate that such existed, nor the revenue associated with the sales from the facilities in question." Moreover, ratepayers are

[59] Although Staff proposed net of tax treatment for post August 1, 1999 interest accruals on the deferred balances and the related recovery of the balances, it did not take a position on the LEAC interest issue in its Briefs, nor did it propose that LEAC interest be accrued net of tax, as stated by the I.D. at 17 and 19.

"credited with the results of sales of excess capacity." The ALJ also found that ACE's retention of NUG energy and capacity to supply 20% of BGS in Year 4 of the Transition Period was consistent with the Final Restructuring Order, and that the retention of the fossil units arguably benefited ratepayers, since the operating costs of these units were assertedly lower or in line with the cost of alternative sources of supply. While noting that Staff agreed with ACE on the excess capacity issue, the ALJ did not accept Staff's recommendation that a detailed review of B. L. England's operation and maintenance costs be performed, as recommended by the Auditors. (*Id.* at 86-90).

With respect to the 13.0% pre-tax return employed in calculating the revenue requirement of the TBD units, the ALJ noted that it had been authorized by the Final Restructuring Order, and that, consistent with basic principles of ratemaking, a fair rate of return to investors should include a return on equity as well as debt. Thus, the ALJ rejected the all-debt rate recommendations proffered by the RPA and NJLEUC. Subject to any contrary determinations by the Board in its then pending B. L. England proceeding, the ALJ additionally found that any change in the rate should be prospective only, and recommended that the rate be set at the overall rate of return found reasonable in the Company's pending base rate proceeding, effective on the date the rates set in that proceeding become effective. (*Id*. at 83-86).

2. Cash Working Capital, TBD Units

Finding that the recovery of cash working capital (*i.e*. a return on cash working capital) falls within the broad language of the Final Restructuring Order, the ALJ rejected the RPA's recommended $3.793 million adjustment for the reasons set forth by the Company and supported by Staff. (*Id*. at 77-82).

3. Restructuring/Consolidated TPS Billing Costs

The ALJ also found that EDECA contemplated the recovery of transition, or restructuring-related costs. Citing P-5, Schedule CFMR-3, the ALJ noted that such costs consisted of $8.990 million expended for enhancements of ACE's Customer Care System; $0.284 million expended on the Balancing and Settlement System; $7.800 million of regulatory and restructuring costs; $3.700 million of Customer Care operating costs; $0.509 million of Balancing and Settlement operating costs; and $0.052 million of load profiling costs. Offsetting these costs were fees of $0.229 million received from third party suppliers during the period 1999-2002. (*Id*. at 90-94).

In rejecting the RPA's proposed disallowance of $15.307 million of these costs, the ALJ found that:

> [Witness] Crane did not dispute the existence of the costs in question, or testify that they were imprudently incurred or that they were unreasonably high or inconsistent with the market. (Tr., pp. 774-775.) Staff and Ratepayer Advocate argue that petitioner's responses to discovery requests regarding those costs were insufficient. However, neither party made a motion to compel

> discovery and, in any event, I am persuaded that there is sufficient detail in the record to conclude that petitioner met its burden of proof. (*See, e.g.*, Exh. P-5, Scheds. CFMR-2 - CFMR-8 & the above findings of fact.) As petitioner argues, to require that each and every pertinent invoice for every bill be provided in order for the Company to meet its burden of proof, especially in the absence of any allegations or allusions in the record to fraud or erroneous booking of expenses, and in the absence of a motion to compel discovery, is not necessary. This is especially so in the current matter, in light of the fact that Auditors were retained to review the deferred balances…As with BGS administrative costs, such costs clearly were not contemplated when petitioner's last rates were set in a base rate proceeding, and there is no other mechanism for recovery thereof other than the deferral accounts.
>
> [*Id*. at 94].

As to the issue of whether a return should be allowed on the unamortized balance of operating costs, and while acknowledging that the Final Restructuring Order did not explicitly address the treatment of restructuring-related operating costs in terms of the amortization period or rate of return, the ALJ found that capital and operating costs should be treated consistently, and that the rate of return applicable to both should be the overall rate of return found reasonable in the Company's pending base rate case, effective on the date the rates approved in that case become effective. (*Id*. at 95).

In summary, on the issue of transition/restructuring-related costs, the ALJ found that the RPA's and Staff's recommendations should be rejected, and that $15.078 million ($15.307 million less the TPS fees of $0.229 million) of such costs should be included in the Company's MTC deferred balance.

C. <u>NNC DEFERRED BALANCE</u>

After reviewing the Company's calculation of the NNC rate proposed to be billed during the period from August 1, 2003 through May 31, 2004, as well as the history of the Company's NUG cost mitigation efforts detailed in the Audit Report, which the ALJ found reasonable, the ALJ addressed the recommended reporting requirements proposed by the RPA and Staff. In denying both, she held that "[t]he ramifications and extent of reporting, including costs thereof, pertinent to Staff's recommendation, especially, are not addressed in the record." (*Id*. at 103).

Noting that the Company did not dispute the Auditors' adjustment of $0.459 million of interest associated with the Pedricktown buyout payment, and that the adjustment was accepted by the RPA and Staff, the ALJ recommended that it be adopted.

In denying the RPA's recommended exclusion of ACE's legal expenses of $2.477 million incurred in the Logan dispute from the NNC deferred balance, the ALJ found that ACE had met its burden of proof, having established that these costs were reasonable, and therefore properly recoverable, whether or not the litigation is successful. Moreover, assuming a continuation of deferred accounting for NUG costs with true-ups, any refunds received, as well as potentially lower expenses in the future from a new contract formula, can be reflected in NNC charges. (*Id*. at 107).

D. <u>SBC DEFERRED BALANCE</u>

1. <u>Universal Service Fund</u>

The ALJ rejected the RPA's and Staff's proposals, and accepted ACE's argument that such proposals would "distort" the customer contribution aspects of the statewide USF and result in "confusion about customer contributions" to that program. (*Id*. at 111, citing the Company's Reply Brief at 17). Since additional post-Transition Period USF funding will be addressed by the Board in a separate order, the ALJ declined to address ACE's proposed deferred accounting and true-up for future USF expenditures. (*Id.*).

2. <u>Clean Energy Program</u>

The ALJ rejected the RPA's proposal, concluding that any treatment of Clean Energy Program costs subsequent to the Transition Period should await the Board's consideration in other dockets currently pending before the Board. She further stated that "[f]or reasons similar to those applicable to the USF, I am persuaded that the [RPA's] proposal should not be adopted." (*Id*. at 114).

3. <u>Uncollectible Accounts</u>

The ALJ adopted the Auditors' recommended adjustment of $1.417 million, but rejected what she interpreted to be the RPA's proposal of including the projected deferred underrecovery pertaining to Uncollectible Accounts in the SBC. (*Id*. at 115-116).

4. <u>Consumer Education Program</u>

The ALJ found that neither the RPA's nor Staff's position was based on record evidence, noting that the letters the RPA relied upon were not offered into evidence during the hearings and therefore were given no weight. (*Id*. at 118). The ALJ concluded that the testimony of ACE's witness was not disputed, and that the Company's position should be adopted, inasmuch as the Auditors found no issues in that respect. (*Id*.).

Citing Orders issued by the Board from September 22, 1998 to April 8, 2002, the ALJ noted that "it arguably is a basic regulatory principle that if a regulated entity has met criteria accepted and approved by the agency with jurisdiction, such would be deemed to be reasonable and prudent and pertinent costs therefore [would] be eligible for recovery in rates." (*Id.* at 121). She additionally concluded that "[t]he fact that utilities were required, over a period of time, to incur expenditures which would be recoverable if they were subsequently deemed to meet future criteria not yet set, and that those criteria and cost allocations were initially made by consultants to the Board, and a consultant to the consultant, raise due process issues if cost recovery is not permitted." (*Id*.). Accordingly, she recommended that ACE's proposed recovery of CEP costs be adopted, subject to Board confirmation that Year 4 costs met applicable standards.

5. Nuclear Decommissioning Funding

With the divestiture of Atlantic's jointly-owned nuclear units and related relief from financial responsibility for the decommissioning of these units, the ALJ found that the nuclear decommissioning component of the SBC is no longer required. (*Id*. at 122).

6. Disposition of the SBC Overrecovery

Finding that the Company had collected approximately $30 million for decommissioning costs not incurred, after considering the positions of the RPA, Staff and the Company as to how the associated net SBC overrecovery should be reflected in rates, the ALJ accepted the Company's position. The RPA had recommended that the decommissioning overrecovery be used to offset underrecovered USF and DSM costs, with the balance returned to ratepayers in the form of a one-time credit. Staff had argued that the issue of the proper method for returning the net overrecovered SBC balance to customers should be addressed in ACE's base rate proceeding, contending that it was the Board's intent to look at all of the Company's unbundled rate components at the end of the Transition Period. In opposing the one-time credit proposed by the Advocate, the Company drew an analogy to the treatment of the overrecovered LEAC balance approved by the Final Restructuring Order, asserting that the four-year amortization of the SBC deferral it proposed would allow the unamortized balance to be applied to higher SBC costs if they materialized, thus avoiding the seesawing of rates the one-year credit proposed by the RPA would entail. In agreeing with the Company, the ALJ also found the RPA's argument as to whether EDECA contemplated different treatment for the SBC deferral, as opposed to other deferred costs, unpersuasive. (*Id*. at 122-124).

E. OTHER ISSUES

1. Interim Deferral Recovery

Although the parties addressed issues pertinent to the recovery period of the deferred balance, the applicable interest rate, the balance to which it should be applied, securitization and other related issues at the hearings and in their Briefs, the ALJ noted that these issues were returned to the Board and did not address them. She did, however, note that there appeared to be no dispute regarding the concept of annual true-ups, and opined that such an approach was reasonable, regardless of the amortization period ultimately determined by the Board. Moreover, it would address concerns expressed by NJLEUC regarding the potential for ACE to overcollect costs. (*Id*. at 124).

2. Interest Calculation

The ALJ did not address Staff's interest proposals, except as noted above in the discussion of the net of tax and LEAC interest issues.

F. RATE DESIGN

The ALJ concluded that the record supported ACE's uniform energy charge, and that NJLEUC's proposed inclusion of loss factors in the MTC and NNC should be adopted. She further concluded that "[i]t is not necessary to determine, at this time, that any specific tariffs should be approved on a "provisional" basis. There is nothing to preclude a party to a base rate proceeding from raising issues regarding tariff design." (*Id*. at 125-128).

G. SUMMARY OF ADJUSTMENTS ACCEPTED BY ALJ

As shown in the table appearing on pages 129 and 130 of the Initial Decision, apart from deducting third party supplier fees of $0.229 million from the deferred MTC balance, the ALJ accepted only the adjustments recommended by the Auditors, and based on the projections of the Company's July 31, 2003 deferred balances determined by the RPA,[60] found the following deferred balances to be reasonable and prudent:

[60] As shown in Exhibit 1 on page 5 of the RPA's Initial Brief. These balances do not include interest. The last projections of the July 31, 2003 deferred balances entered into the record by the Company are those appearing on Schedules HACR-10 and HACR-15 attached to witness Chalk's Rebuttal Testimony (P-13) filed on January 24, 2003. As shown on HACR-10, based on actual data through December 2002, the Company projected an underrecovered BGS deferred balance of $70.392 million, an overrecovered NNC deferred balance of $5.173 million, an underrecovered deferred MTC balance of $126.984 million, and an overrecovered deferred SBC balance of $21.108 million, for an aggregate underrecovered deferred balance of $171.095 million projected as of July 31, 2003 before interest. After adding interest of $8.887 million, as calculated on HACR-15, the Company's projected aggregate deferred balance was $179.982 million, as compared to the comparable balance as filed of $176.439 million, including interest of $10.205 million. The RPA's update was determined by adding the deferrals projected for the months of February through July 2003 in Schedule HACR-10 to the Company's actual deferred balances as of January 31, 2003, from Schedule HAC-1 included with the Company's January 2003 update distributed to the parties by letter dated March 5, 2003.

Summary of Adjustments
and Deferrals Recommended by the ALJ *
($ Millions)

BGS	
Company Claimed BGS Deferral	$72.512
Audit Recommendation	(6.100)
BGS Deferral	$66.412
NUG	
Company Claimed NUG Deferral	$(6.365)
Audit Recommendation	(0.459)
NUG Deferral	$(6.824)
MTC	
Company Claimed MTC Deferral	$125.682
Audit Recommendation	(2.617)
Credit	(0.229)
MTC Deferral	$122.836
SBC **	
Company Claimed SBC Deferral	$(20.083)
Audit Recommendation	(1.417)
SBC Deferral	$(21.500)

* ( ) denotes an overrecovery.

** corrected to show an overrecovery (credit balance).

V. EXCEPTIONS AND REPLY EXCEPTIONS

Exceptions to the Initial Decision were filed by ACE, the RPA, NJLEUC, Cogentrix and Staff. Reply Exceptions were filed by ACE and the RPA.

A. THE COMPANY

While agreeing that the ALJ properly rejected the disallowances recommended by the other parties, ACE took exception to the ALJ's adoption of the Auditors' recommendations: the excess capacity adjustment of $6.1 million (ACE Exceptions at 4); the recommended re-pricing of the payments made for the purchase of capacity from Deepwater and the transferred CTs during the period from August through December 1999 (*Id.* at 13); and the recommended reduction in the allowance for uncollectible accounts. (*Id*. at 15).

In its Reply to the Exceptions of the other parties, ACE argued that any determination that an expense was unreasonable or imprudent must be supported by facts in evidence; that the majority of the ALJ's findings were based on such facts; and that the ALJ's extensive reliance on the Audit Report was well placed. The adjustments proposed by Staff, the RPA, NJLEUC and Cogentrix on the other hand should be rejected as they were assertedly not supported by record evidence. (ACE Reply Exceptions at 1-3).

In response to the RPA's exception to the ALJ's rejection of the RPA's proposed LEAC interest adjustment, the Company cited the ALJ's findings that witness Chalk's testimony on this issue was persuasive, and that the Company's prior practice was consistent with the Board's regulations. ACE further argued that because there was no change in the LEAC rate during the period at issue, the RPA's approach created an arbitrary interest calculation designed for the "sole purpose of manufacturing a claim for additional interest to be provided to the Company's customers." ACE additionally contended that in accordance with N.J.A.C. 14:3-13.4(c), interest on under or overrecovered LEAC balances had always been calculated on the full deferred balance, not on the net of tax balance, as assertedly proposed by Staff and the RPA.[61] (*Id*. at 3-6).

In defending its BGS procurement, the Company took issue with the RPA's focus on "prudent" as opposed to "reasonable" costs, asserting that before there can be any disallowance of any BGS expense, the Board must make a finding that the expense was unreasonable. With the exception of the adjustments recommended in the Audit Report, ACE claimed that no party provided any evidence that its BGS expenses were unreasonable. (*Id*. at 7).

In challenging the RPA's assertion that ACE should have entered into a contract in 1999 that covered its BGS supply needs in the summer of 2001, ACE contended that there was no evidence to suggest that it could have found a supplier willing to enter into such a contract, given the many unknowns at that time. NJLEUC, in fact, had assertedly argued the opposite: that it was naïve for the Company to have even considered seeking a long-term contract in 1999. The Company asserted that there was no record evidence to indicate that either its early RFPs (or even its failure to file an RFP with the Board in September 1999) or later RFPs

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61 However, both Staff's and the RPA's net of tax interest proposals applied only to post-August 1, 1999 deferrals and deferral recovery, not to the calculation of the LEAC interest adjustment, as asserted by the Company. While agreeing with the Company on the LEAC interest issue in its Exceptions to the Initial Decision, Staff took no position on the issue in its Briefs. Similarly, in proposing its $1.993 million LEAC interest adjustment, the RPA's witness Crane simply accepted the Company's calculation of LEAC interest for the months of June 1998 through July 1999, as shown in Schedule HAC-2 attached to witness Chalk's Direct Testimony (P-11). As shown there, an assumed interest rate of 10.52%, the Company's last allowed overall rate of return, was applied monthly to the beginning and end average of the cumulative under or overrecovered LEAC balance, unreduced by the related deferred income taxes.

resulted in any unreasonable or imprudent costs, including the costs the Company incurred in the summer of 2001. (*Id*. at 6-11).

In response to the RPA's exception to the ALJ's rejection of the RPA's recommended excess capacity disallowance, the Company reiterated the ALJ's findings on this issue. (*Id*. at 11-13)

In response to both the RPA's and NJLEUC's contention that it was unreasonable for the Company not to have entered into a parting contract with its affiliate,[62] ACE asserted that the RPA had opposed that option in ACE's restructuring proceedings. Moreover, NJLEUC's contention (at page 14 of its Exceptions) that ACE should have entered into a parting contract with its affiliate similar to the contract PSE&G entered into with its unregulated affiliate, was not an option contemplated in the Final Restructuring Order. (*Id*. at 13-14).

Contending that parting contracts were not necessarily "the panacea some parties would make them out to be," the Company cited the Board's language in the Final Restructuring Order at 91, indicating that their purpose assertedly was to facilitate the sale of the Company's generation assets: "The Board recognizes that the use of parting contracts entered into by the Company with purchasers of its generation assets, as part of the sale of such assets to those purchasers, to the extent they make possible or enhance the sale of such assets, can be in the public interest." Thus the parties who criticized the lack of a parting contract were asserted to have "improperly assumed that such a contract would not be above market (to facilitate a sale), but below market (that is, the buyer of the asset would purposely agree to a below-market power contract)." (*Id*. at 14).

In responding to Staff's Exceptions, in which Staff compared the Company's BGS costs to PJM spot market purchases, and while noting that Staff did not use its analysis to quantify its recommended disallowance, the Company asserted that it would be "completely improper for the Board to rely on this extra-record, faulty analysis." (*Id*. at 15). Moreover, the Company contended that Staff's comparison of the Company's BGS costs to those of JCP&L and RECO was similarly flawed:

> Staff also repeats its comparison of Atlantic's average contract cost, to the average contract cost for other utilities. Again, this was not done on the record, and the Company had no opportunity to address the flaws in that analysis. Among the major problems with such comparison is the fact that those two companies purchased all of their BGS supply through third party contracts (including base load supply), while Atlantic only used contracts to meet the supply needs over and above supply already available from the retained generation and the NUGs. JCP&L and Rockland

[62] While the RPA noted that the Final Restructuring Order permitted the Company, as a BGS supply option, to "utilize its affiliated service company to make arrangements for BGS supply" (RIB at 20, quoting paragraph 10 on page 88 of the Final Restructuring Order), unlike NJLEUC, the RPA did not contend that the Company should have done so.

> would therefore have different needs with respect to their contracts, and could, for a substantial portion of their loads, expect to have to provide long-term service. In essence, Staff is comparing JCP&L and Rockland's cost to serve all of their BGS load (the base and the portion that varied over the transition period) with Atlantic's cost to serve the variable portion only. This is not a valid comparison.
>
> [*Id*. at 15].

In asserting that it had fully supported the recovery of its BGS administrative costs, the Company cited the testimony of witness Morgan and the ALJ's findings. (*Id*. at 16).

In response to the RPA's exception to the ALJ's rejection of the RPA's proposed disallowances associated with the Company's calculation of the revenue requirement of the TBD units, the Company: 1) cited the testimony of witness Morgan on the cash working capital issue and the ALJ's finding for the Company on this issue (*Id*. at 17-18); 2) contended that the proposed reduction in the 13.0% pre-tax return to ACE's cost of debt "would violate Constitutional requirements that the Company be permitted a fair return on its investment" and that the ALJ properly rejected such a reduction on the basis that the inclusion of an equity return in the overall rate of return is consistent with basic principles of ratemaking (*Id*. at 18); and 3) argued that ACE should not be penalized for the failed NRG sale, as it would be if the RPA's recommended disallowance of the above-market costs of the TBD fossil units, less an imputed return on their stranded costs, were accepted on the basis that these units became excess capacity as a result of the failed sale. (*Id*. at 19-20). With respect to NJLEUC's contention that the BGS deferral represented lost revenues rather than stranded costs, and could be offset by higher revenues after the deferral period, ACE asserted that all of its BGS load would be served by third parties after August 1, 2003, and that the related revenue received from customers would not be retained by the Company, but paid to the third parties. (*Id*. at 21).

Citing Mr. Morgan's testimony and the ALJ's findings, ACE asserted that its transition-related costs and consolidated TPS billing costs were actually incurred and fully recoverable absent a showing of imprudence. (*Id*. at 21-24).

As to the parties' exceptions to the ALJ's finding that approximately $2.4 million of legal costs incurred in the Logan dispute should be included in the NNC deferral, since customers are likely to see benefits of at least $3.2 million plus interest for alleged overcharges during the period from February 9, 2000 through December 31, 2002, as well as estimated future benefits of approximately $1 million per year over the 22-year remaining life of the Logan PPA, the Company maintained that the costs incurred to achieve these benefits should be recovered. (*Id*. at 25-26).

In responding to the RPA's exception to the Company's proposed recovery of CEP costs, ACE cited the testimony of witness Janocha, and noted that these costs were incurred pursuant to a

Board Order, and that the results of the Company's CEP program during its first three years were additionally evaluated by the Board. (*Id*. at 26).

In concluding its Reply Exceptions, ACE opposed the separate treatment of the SBC deferral proposed by the RPA, and defended the Company's proposed use of a uniform energy charge in billing MTC costs, maintaining that it would not violate EDECA's prohibition against cost shifting, which, the Company claims, was intended to apply only to the initial unbundling of ACE's rates. (*Id*. at 26-27).

B. <u>RATEPAYER ADVOCATE</u>

<u>LEAC Interest/BGS Deferrals</u>

After asserting that the ALJ's rejection of its proposed $1.993 million LEAC interest adjustment ignored the Board's regulations and Company history (RPA Exceptions at 1), the RPA took exception to the ALJ's findings on the Company's BGS deferrals, characterizing them as "inexplicable" in view of her findings: "The Initial Decision in the present case leaves more questions than answers. Throughout the decision, the ALJ time and again recognizes the Company's poor performance and lack of sound business judgment during the BGS Energy and Capacity procurement process. Nevertheless, contrary to her own factual findings, the ALJ inexplicably grants the Company close to full recovery of the deferred balance." (*Id*. at 11).

While recognizing that market energy and capacity prices were beyond the Company's control during the Transition Period, the RPA argued that ACE "did have control over whether it complied with Board Orders and hired competent staff to take advantage of the new competitive market instead of being at its mercy." (*Id.* at 16). Because ACE's management failed to plan and execute a reasonable BGS procurement strategy and failed to comply with Board Orders to obtain approval of a winning bid in a timely manner, the Company assertedly paid excessive costs for energy and capacity. *(Id.* at 13). Accordingly, the RPA contended that, contrary to the ALJ's findings, the Board should disallow the excessive energy charge of $25.527 million the RPA claims the Company incurred in July and August 2001, and should also accept the RPA's recommended excess capacity disallowance of $3.375 million. (*Id.* at 16). The RPA additionally argued that by rejecting its proposed disallowance of BGS administrative costs on the basis that the RPA did not show that the claimed amount was already included in ACE's base rates, the ALJ improperly shifted the Company's burden of proof. (*Id*. at 18-21).

<u>NNC, MTC, SBC Deferrals and Rate Design</u>

As to the NNC deferred balance, the RPA took exception to the ALJ's rejection of both the RPA's uncontested recommendation that ACE report its NUG mitigation efforts annually to the Board, as well as the RPA's recommended elimination of the costs of the Logan arbitration from the deferred NNC balance pending the outcome of the dispute. (*Id*. at 22 -25).

As to the MTC deferred balance, the RPA contended that the ALJ should have: 1) accepted the RPA's proposed working capital adjustment and reduced the MTC deferred balance by $3.793

million (*Id.* at 26); 2) prospectively reduced the 13.0% pre-tax rate of return allowed on the Company's TBD assets to a rate based on the Company's cost of debt (*Id*. at 27-30); 3) disallowed $29.569 million of above-market costs of TBD fossil generation costs on the basis of ACE's asserted 20% excess capacity, post August 1, 2002 (*Id*. at 30-32); 4) disallowed transition-related costs of $15.078 million (*Id*. at 33); and 5) disallowed customer account services ("CAS") costs of $4.052 million (*Id*. at 34).

With respect to the SBC deferred balance, the RPA took issue with the reasons cited by the ALJ in rejecting the RPA's proposed treatment of USF costs (*Id.* at 36-37), and asserted that the ALJ's findings on DSM and Clean Energy Program costs were ambiguous, unclear and confusing. The RPA reiterated its recommended treatment of these costs, *i.e.*, that the DSM underrecovery be included in the SBC deferred balance, which in turn should be refunded to ratepayers over one year, and that the Clean Energy component proposed to be added to the SBC rate by the Company not be set at this time, but prospectively in the Board's ongoing Clean Energy proceedings. (*Id*. at 38-41; 46). As to Uncollectibles, the RPA asserted that there was an inconsistency in the ALJ's finding on the Auditors' recommended $1.417 million adjustment, and clarified that the RPA had proposed including this adjustment in the overrecovered SBC balance, whereas the issue between the RPA and the ALJ appeared to be whether the SBC balance should be refunded to ratepayers over one year, or included in the 4-year amortization of ACE's deferred balances proposed by the Company. (*Id*. at 41-42).

As to Consumer Education Program costs, the RPA contended that ACE had not sustained its burden of proof, *i.e.*, that it had not demonstrated that these costs were reasonably and prudently incurred, nor had it even mentioned in its testimony the "Measures of Success" standard established by the Board governing the recovery of these costs. (*Id*. at 42-43). Consistent with its proposed treatment of the other components of the deferred SBC balance, the RPA also took exception to the ALJ's acceptance of the Company's inclusion of the overrecovered balance of decommissioning costs in the aggregate deferred balance the Company proposed recovering over four years, contending that the EDECA envisioned different treatment of SBC deferrals as compared to BGS, NNC and MTC deferrals. Accordingly, the RPA urged the Board to adopt its recommended refund of the overrecovered SBC balance to ratepayers over one year. (*Id*. at 43-45; 46).

As to rate design, the RPA took exception to the ALJ's adoption of NJLEUC's proposed inclusion of loss factors in calculating MTC and NNC charges on the basis that it was not known whether line losses had already been reflected in the Company's cost allocation and rates. Thus, the RPA recommended that this issue be addressed in ACE's pending base rate case, along with the Company's proposed change in the current demand and energy-based MTC cost recovery. Noting that ACE's current MTC rates were developed during the restructuring process to preserve revenue neutrality, and accordingly that no attempt was made at that time to assign costs on a causal basis, the RPA urged the Board to adopt, only provisionally, the Company's proposed energy-only MTC cost recovery, and to consider this issue further in the Company's pending base rate case. (*Id*. at 47-49).

Citing N.J.S.A. 48:3-50.c.(4) and 48:3-57.e, the RPA asserted in its Reply Exceptions that EDECA gives the Company the opportunity, but not the right to recover its prudently incurred deferred BGS costs, subject to the Company "having taken and continuing to take all reasonably available steps to mitigate the magnitude of its above-market electric generation and power supply costs." Similarly, EDECA requires a showing that such costs are not "already being recovered in other elements of [the Company's] charges" in order for them to be recoverable. Thus, before incurred costs can be recovered in rates, the Company must show that they were reasonably and prudently incurred, that it took all reasonably available steps to mitigate such costs, and that the costs are not already being recovered in rates. In the instant case, the RPA averred, the Company had shown "none of the above." (RPA's Reply Exceptions at 2-3).

Responding to ACE's argument that the ALJ properly rejected the RPA's proposed disallowance of $25.5 million of third party purchase costs incurred in July and August 2001 on the basis that the RPA's witness could not identify a single energy transaction that was imprudent, the RPA asserted that the onus was not on it to demonstrate the imprudence of a single energy transaction, but rather that the Company must "demonstrate that its actions, taken as a whole, in the procurement of BGS were reasonable and prudent," as recognized by the ALJ at 61-62 of the Initial Decision quoted *supra.* (*Id*. at 3).

In further support of its contention that ACE's procurement process was flawed, the RPA cited a lack of a competent staff (*Id*. at 4-5), as well as the Company's asserted failure to provide that staff with adequate resources (*Id*. at 5-6), as evidenced by the Auditors' finding that the Company does not "routinely gather market intelligence on consummated forward contracts, nor does it track and evaluate bilateral transactions in conjunction with independent projections of congestion cost risks." (*Id.* at 5, citing AUD-2 at VIII-25). The Auditors further found that "[a]lthough a Conectiv organization routinely projects PJM prices on a daily basis, this information is not provided to the individual responsible for BGS procurement", and that the Company did not use models or tools to implement its BGS procurement strategy, nor did it routinely use a decision model to balance spot purchases with forward contracts. (*Id.* at 6*,* citing AUD-2 at VIII-26). Nor, the RPA asserted, was the Auditors' finding that the Company was imprudent for purchasing only 200 Mw of capacity offered in response to RFP III based on hindsight, *i.e.*, market prices which became evident only after the purchase decision was made, as argued by the Company in excepting to the ALJ's adoption of the Auditors' recommended $6.1 million capacity disallowance. (*Id.* at 7).

Moreover, ACE failed to negotiate parting contracts despite the Board's encouraging it to do so, not only for the purpose of enhancing the sale value of its generating assets, but as a means of mitigating its BGS costs, as recognized by the Board in the Final Restructuring Order [63] and by the ALJ:

[63] At 80, where the Board recognized that the "negotiation of transition power purchase agreements or "parting contracts" as part of a generation asset sale, whereby the buyer agrees to sell some or all energy, capacity and/or other services from the purchased generating plants to the seller for some limited period of time, may be negotiated as an integral part of any asset sale agreement in connection with the

> I give some weight to the fact that the record does not indicate why petitioner did not attempt to negotiate a parting contract with [Conectiv Energy Services, Inc.], to which the Company's CTs which had capacity exceeding 500 MW, were transferred at net book value, which, as NJLEUC argues, would have reduced the need to make an equivalent purchase in the spot market. Related to intervenor's argument is the fact that petitioner did not consider utilizing the shopping credit as a benchmark for prices. Although the 500 MW of supply from the CTs would not have put petitioner in a position to avoid any acquisitions in the spot market, it may have mitigated the result of the price increases occurring in the summer of 2001.
>
> [I.D. at 64, as quoted in the RPA's Reply Exceptions at 8].

Again in reference to the potential use of the shopping credit as a benchmark rate for negotiating a parting contract, the ALJ noted:

> I am also persuaded, to an extent, by NJLEUC's analysis that, in light of the fact that the shopping credit rate was above rates prevailing in the PJM wholesale market during 1999 and 2000, parting contracts might have been considered if the shopping credit were used as the benchmark rate. In addition, the fact that NRG did ultimately enter a parting contract agreement raises questions regarding why petitioner did not explore such options earlier.
>
> [I.D. at 68, as quoted in the RPA's Reply Exceptions at 9].

Moreover, Company witness Elliott was aware of the cost mitigating purpose underlying the Board's parting contract recommendation, as well as the other cost mitigation options set forth in the Final Restructuring Order, as he noted during cross-examination:

> I think our understanding was that it was Atlantic City Electric's task to try to mitigate the risks as best as possible using all of the various tools that were available to it to do it and that could consist of RFPs. It could consist of fixed purchases which would be hedges against the market prices. It could be looked at as far as the parting contracts with divested units or it could be financial hedges. Basically all of these things I think we've spoken to, you

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divestiture(s), and can serve to protect ratepayers from the vagaries of the developing competitive energy market during the transition to competition."

> know, previously, that those were tools that suppliers or purchasers can use to try to mitigate risk.
>
> [Tr. 251].

Viewed as a whole, the RPA contended that ACE's BGS procurement was unreasonable and imprudent, and thus that the record fully supported the RPA's recommended BGS disallowances totaling $40.523 million, in contrast to the $6.1 million disallowed by the ALJ. (RPA Reply Exceptions at 10-11).

In concluding its Reply Exceptions the RPA urged the Board to adopt the Deepwater and CT capacity re-pricing adjustment recommended by the Auditors and accepted by the ALJ, as well as the ALJ's decision to adopt the Auditors' recommended $1.417 million adjustment to the Company's allowance for uncollectible accounts. (*Id*. at 11-15).

C. NJLEUC

NJLEUC took exception to the ALJ's disallowance of only $6.1 million of ACE's deferred BGS costs, as well as the ALJ's allowance of all of the Company's petitioned for transition-related regulatory costs, including capital expenditures on its Customer Care system. NJLEUC also took issue with the ALJ's adoption of the Company's proposed uniform energy rate to recover MTC costs, asserting that the current demand and energy-based recovery should continue. NJLEUC additionally recommended reducing the Company's allowable transition-related regulatory costs, and the deferred BGS balance to $24.5 million. (NJLEUC Exceptions at 1-2).

In support of its recommended BGS disallowance, NJLEUC averred that the Initial Decision and the record itself "chronicles at length [the Company's] inexplicable, continuing failure to avail itself of deferral-mitigating tools clearly within its control – parting contracts, hedging arrangements and long-term bilateral contracts – and its attendant failure to properly select, and thereafter adequately support, competent decision-makers capable of making reasonable and prudent supply decisions on behalf of the Company's customers." (*Id*. at 4).

D. COGENTRIX

Cogentrix took issue with the ALJ's finding that the Company's claimed $2.47 million of legal and other costs expended in the dispute with the Logan project should be included in the NNC deferred balance, recommending instead that such costs be excluded pending the outcome of the dispute, as proposed by the RPA. As a further reason for excluding the Logan costs from the NNC balance at this time, Cogentrix contended that they had not been sufficiently documented by the Company, *i.e.*, that the Company had not sustained its burden of proof required for the pass-through of these costs to ratepayers. (Cogentrix Exceptions at 1; 27-31)

E. BPU STAFF

Interest Calculation

Staff took exception to the ALJ's findings on how interest should be calculated (the net of tax issue), which in the Initial Decision was discussed in connection with the LEAC interest adjustment proposed by the RPA. While noting that interest on net LEAC overrecoveries was historically calculated on the full, as opposed to the net-of-tax deferred balance, the ALJ found that "[t]he difference between calculating interest on the full balance with a net of tax effect is, ultimately, a "timing difference," the net effect is the same…" (I.D. at 16) While the ALJ correctly asserted that Staff proposed accruing interest on ACE's deferred balances during both the accrual and recovery periods net of tax, she mistakenly states that "the application of Staff's adjustment to the LEAC overrecovery would decrease the levelized annual payment by approximately $2,000,000." (*Id.* at 17).

In its Exceptions, Staff accordingly pointed out that the $2 million reduction was unrelated to the LEAC adjustment, but was instead the reduction in the annual payment calculated by the Company to recover its aggregate deferred balance over four years that would result if the recovery were based on the deferred balance, net of tax, as compared to the "gross" balance (the balance not reduced by the related accumulated deferred income taxes), as the Company agreed would be the case. (Staff Exceptions at 3; Exhibit S-8).

This reduction, Staff averred, properly reflected the fact that the tax reduction received when the deferred costs are incurred reduces the amount of the deferred balance that must be financed during the Transition Period. While it is true that the tax benefit (the deferred income taxes) must be paid back during the period in which the deferred costs are recovered (the post-Transition Period), in the interim, the deferred taxes represent cost-free capital on which no return, *i.e.*, interest, is due, as Staff noted in its Reply Brief at 7. As applied to the 4-year amortization of the aggregate deferred balance proposed by the Company, Staff calculated that the reduction in total interest that would result from net of tax recovery would be about 42% ($12.0 million, net of tax, as compared to $20.8 million, gross). (*Id*. at 4).

While the comparison was not exact, Staff also asserted that calculating interest on ACE's combined BGS, NNC and MTC deferred balances during the Transition Period, net of tax, would yield an interest accrual of $3.362 million, as compared to the $8.887 million calculated by the Company,[64] as shown in Appendixes SRB-1 and SRB-2 attached to Staff's Reply Brief. (*Id*.).

[64] As shown in Schedule HACR-15 attached to P-13. That schedule, however, reflected actual data through December 2002, the overrecovered SBC balance, no disallowances and simple interest (no compounding). Staff's calculation on the other hand did not include the SBC balance, reflected actual data through January 2003, interest compounded annually, Staff's recommended BGS and NNC disallowances of $35.480 million and the elimination of the misclassified regulatory asset amortization of $2.617 million included in the MTC balance. In an exact comparison with all else held constant, net of tax interest accruals will be less than "gross" accruals by the tax rate percentage (40.85%), as shown by Exhibit S-7 in which, based on actual data through December 2002, the Company calculated gross interest on its aggregate deferred balances of $8.893 million as compared to $5.259 million, net of tax.

Staff additionally excepted to the ALJ's finding that the Company's interest calculation was "consistent with pertinent BPU regulations" (N.J.A.C. 14:3-13.4 (a)) *i.e.*, that this regulation was in any way relevant to the post July 31, 1999 period, in that the LEAC was terminated as of that date and its interest calculation methodology superseded by the provisions of the Final Restructuring Order. Again referring to its Reply Brief, Staff asserted that the reference to the superseded LEAC in the Final Restructuring Order states only that the deferred balances should be recovered through a mechanism similar to that employed with the LEAC, and while specifying the interest rate to be used (the yield on constant maturity seven-year treasury notes plus 60 basis points), the Final Restructuring Order is silent on the balance (net of tax or gross) to which the interest rate is to be applied. As argued in more detail in its Reply Brief, Staff reiterated that net of tax treatment is the appropriate treatment from the standpoint of sound regulatory practice, that it will result in desirable standardization among the four electric utilities, and that it is in accordance with recent Board decisions that seek uniform treatment of interest accruals in those instances where tax benefits effectively reduce financing costs. (*Id*. at 5).

BGS Procurement

Although Staff agreed that the ALJ made many sound findings relative to the shortcomings in ACE's BGS procurement, they were not, in Staff's view, appropriately reflected in her decision on the recommended BGS disallowances. (*Id*. at 6).

As the ALJ clearly stated, these shortcomings were evident at the very start of the Transition Period and continued throughout the period: "a review of the record as a whole supports a conclusion that, for whatever reasons, petitioner did not initially take steps that would have been reasonable at the time to gain better control over the entire procurement process." (I.D. at 62). The ALJ further found that, "[a]s the Auditors testified, reasonable and prudent management would have been to assure that the decision-makers were the most qualified to make important supply decisions, especially given the uncertainty at the time in question and the new environment of deregulation *per se*." (*Id*.). The Company's initial BGS portfolio manager, who was responsible for BGS supply until the end of 2000, had no experience in energy supply whatsoever and was not even working full time on BGS supply activities. (*Id*. at 22). While ACE ultimately hired a consultant to assist it in designing the first two RFPs, the consultant's scope of work "did not provide [ACE] with the needed level of assistance and expertise, given the level of [ACE's] own capabilities." (*Id*. at 43). Additionally, as the Auditors concluded, ACE did not effectively manage its relationship with the BPU, and the RFP development and analysis processes were "flawed." (*Id*.). (Staff's Exceptions at 5-6).

At pages 6 through 9 of its Exceptions, Staff cited additional findings of the ALJ that indicated the Company's BGS procurement process was deficient. As evidence of the Company's poor management of its relationship with the Board, the ALJ cited the Company's failure to submit plans for its RFP process to the Board by September 15, 1999, with the goal of concluding the process and entering into a contract for BGS supply by December 15, 1999. (I.D. at 63).

Citing the Auditors' findings, the ALJ observed that the Company failed to go beyond simply comparing the RFP bids to each other until requested by the Board, and did not routinely use a decision model to balance spot purchases with forward purchases. (*Id*. at 42-44).

Apart from the shortcomings of its RFP process, the ALJ found that ACE did not appropriately consider parting contracts. As stated by the ALJ, "Although petitioner's analysis regarding the probability of parting contracts may have some merit in general, the lack in the record of attempts to negotiate parting contracts, and the fact that petitioner expressly did so at the behest of the BPU, supports the arguments of the other parties." (*Id*. at 67). The ALJ also gave weight "to the fact that the record does not indicate why petitioner did not attempt to negotiate a parting contract with CES, to which the Company's CTs, which had capacity exceeding 500 Mw, were transferred…" (*Id*. at 64). Finally, the ALJ was "persuaded, to an extent, by NJLEUC's analysis that, in light of the fact that the shopping credit rate was above rates prevailing in the PJM wholesale market during 1999 and 2000, parting contracts might have been considered if the shopping credit were used as the benchmark rate. In addition, the fact that NRG did ultimately enter a parting contract agreement raises questions as to why petitioner did not explore such options earlier." (*Id*. at 68).

Moreover, the ALJ cited the Auditors' finding that the Company was reluctant to take any action without the BPU's "full support." (*Id*. at 45).

In that respect the Board made it very clear that ACE was responsible for prudently procuring its BGS supply during the Transition Period, as well as for complying with the Board's directives. As noted by the ALJ at page 56 of the Initial Decision, the Board, in its May 30, 2000 Order, [65] stated:

> …In addition, the elapsed time between the completion of the RFP process and the issuance of the BGS contracts does not allow sufficient time for Board Staff and the Ratepayer Advocate to adequately and properly evaluate such issues as the appropriate duration of the supply contract or the reasonableness of Atlantic's determination of its supply needs. Moreover, the Board cannot ignore the fact that Atlantic has violated its commitment to file for Board approval of the RFP process by September 15, 1999… Atlantic does not now come before the Board with clean hands. Inasmuch as Atlantic has unilaterally opted to purchase capacity and energy in the open market without seeking some specific relief from its express commitment to the Board and other parties to use a structured competitive process, the Board FINDS the company should bear the full burden of its actions and be at risk for the consequences thereof. We do not feel compelled to

65 *I/M/O Atlantic City Electric Company for Approval of a Request for Proposals, Authorization of a Competitive Procurement and to Enter into a Contract for Basic Generation Service Supply,* Docket No. EM00030156, Order dated May 30, 2000.

> sanction the present ramifications and consequences of such indifference by Atlantic to what we consider to be legitimate good faith commitments that all parties have the right to rely upon.
>
> [May 30, 2000 Order at 2].

Given the shortcomings cited by the ALJ, Staff averred that the Company, not ratepayers, should bear the burden of the Company's imprudent management. Moreover, Staff contended that had the Company managed its BGS procurement more effectively, its BGS supply costs would have been substantially lower. (Staff Exceptions at 9-10).

Potentially how much lower was quantified by Staff by comparing ACE's cost of energy and capacity, other than that obtained from its to-be-divested generating units and under long-term pre-transitional power purchase agreements, to both the cost of the same energy if it had been purchased from PJM, and the cost if it had been obtained at the average cost achieved by JCP&L and RECO during the first three years of the Transition Period. As calculated in Appendix SIB-2 attached to Staff's Initial Brief, and after reflecting a very conservative allowance for capacity costs, Staff estimated that the average cost of energy and capacity if purchased from PJM would have been $49.32 per Mwh, as compared to the average cost of the Company's actual PJM and third party energy and capacity purchases of $72.38 per Mwh during the first three years of the Transition Period. After applying the difference of $23.06 per Mwh to the 7,168 Gwh purchased, Staff's analysis showed that ACE's purchased power costs would have been about $165.3 million lower if all of its discretionary energy and capacity purchases had been made from PJM. (SRB at 40).

Similarly, if ACE had been able to achieve the same average cost of energy and capacity as did JCP&L[66] and RECO, its BGS procurement costs would have been lower by $162.7 million and $121.9 million, respectively.

Given the magnitude of this difference, Staff found the BGS disallowances proposed by the RPA and the Auditors ($35.021 million in total) to be extremely generous, and appropriate for the very reasons cited by the ALJ.

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66 Parting contracts, since they are discretionary in the sense that the Company could have elected to enter into them upon the divestiture of its generating units if it chose to (as did JCP&L and RECO), were included in Staff's determination of the average cost of JCP&L's and RECO's discretionary purchases, as noted in Appendix SIB-3 attached to Staff's Initial Brief. In its Exceptions, Staff incorrectly noted (in footnote 6 on page 10) that the cost of JCP&L's discretionary purchases, as calculated in Staff's Initial Brief submitted in JCP&L's deferred balances proceeding (Docket No. ER02080507) had been revised to $50.2 per Mwh in an incorrect reference to the table on page 128 of the Brief. The cost shown there is the average cost of all sources of JCP&L's BGS supply (with purchases under NUG and utility PPAs included at market value), not the cost of discretionary supply. As noted supra, however, both the cost of the Company's and JCP&L's discretionary purchases has since been revised, as shown in Exhibit 3 attached.

VI. DISCUSSION AND FINDINGS

As described in detail above, these matters have come before the Board as a result of the requirements of EDECA and the Board Orders implementing EDECA. In particular, EDECA required that as of August 1, 1999, each electric utility provide Basic Generation Service, at rates approved by the Board, to customers who did not choose an alternate power supplier, and further provided that these utilities would be permitted to recover, on a full and timely basis, all reasonable and prudently incurred costs incurred in the provision of BGS, subject to the provisions of EDECA. N.J.S.A. 48:3-57.e. EDECA also provided that the BPU could devise an "alternate accounting or cost recovery process" to enable the utilities to provide BGS to customers and at the same time sustain the mandated rate reductions during the Transition Period. N.J.S.A. 48:3-57.b.(3).

Pursuant to these and other relevant provisions of EDECA, the Board issued its Summary and Final Restructuring Orders, whereby ACE was directed, among other things, to implement certain rate reductions during the Transition Period (Final Restructuring Order at 83-84); to implement non-bypassable SBC, MTC, NNC charges to recover certain defined types of costs, which would be subject to deferred accounting, with interest, with review and true-up at the conclusion of the Transition Period (*Id*. at 84, 92-94); and to provide Basic Generation Service at Board-approved rates to customers who did not choose an alternate energy supplier (*Id.* at 84-89). The Restructuring Orders recognized that ACE might have to defer recovery of some portion of its BGS costs in order to fund and sustain the rate reductions through the end of the Transition Period. The Restructuring Orders provided that the Company's deferred balances would be audited by the Board and that those deferred costs determined to be reasonable and prudent would be recoverable with interest at the end of the Transition Period through a non-bypassable charge, in a manner and timeframe to be determined by the Board. *(Id. at 93).*

In order to allow for adequate time for the Board to review and reset all unbundled rate components by the end of the Transition Period, the Final Restructuring Order required ACE to make a timely filing, no later than August 1, 2002, as to the proposed level of all unbundled rate components to go into effect on August 1, 2003. *(Id. at 84).*

As noted above, ACE filed the instant deferred balances Petition on August 1, 2002, and supplemented its Petition on August 30, 2002, to provide the information requested in the Board's July 22, 2003 Order, *supra*. Its base rate petition was filed on February 1, 2003, and remains pending at the Office of Administrative Law. This Final Order addresses only the deferred balances Petition.

The Board **FINDS** that the deferred balances proceedings conducted by Administrative Law Judge Diana C. Sukovich were thorough and complete and provide an adequate record. The Board acknowledges and appreciates the efforts of ALJ Sukovich in presiding over this proceeding and in producing a detailed and thorough Initial Decision. Based on its review of the extensive record in this proceeding, which has been summarized hereinabove, the Board has determined that the Initial Decision, subject to certain modifications, which will be set forth and discussed herein, represents an appropriate resolution of this proceeding. Accordingly, the Board **HEREBY MODIFIES** the Initial Decision as described below.

A. BGS DEFERRED BALANCE

1. Standard of Review

Pursuant to its statutory mandate, the BPU is required to ensure that public utilities provide New Jersey consumers with safe, adequate and proper service at just and reasonable rates. N.J.S.A. 48:2-21; N.J.S.A. 48:2-23. Consistent with long established and well-settled principles of law, in a rate proceeding the utility must bear the burden of proof with respect to all elements of its expenses which it seeks to pass through in rates to its customers. *In re Public Service Electric and Gas Co.* 304 N.J. Super. 247 (App. Div. 1997), cert. den. 152 N.J. 12; *Public Service Coordinated Transport v. State,* 5 N.J. 196 (1950).

In implementing EDECA, the Legislature declared numerous policy goals related to the need to lower the high cost of energy, ensure universal access to affordable and reliable electric power service, and the provision of a smooth transition from a regulated to a competitive supply power marketplace, including provisions which afford fair treatment to all stakeholders during the transition. N.J.S.A. 48:3-50.a.(12). In particular, the Legislature declared that it was in the public interest to:

> Provide each electric public utility the opportunity to recover above-market generation and supply costs and other reasonably incurred costs associated with the restructuring of the electric industry in New Jersey, the level of which will be determined by the Board of Public Utilities to the extent necessary to maintain the financial integrity of the electric public utility through the transition to competition, subject to the achievement of the other goals and provisions of this act, and subject to the public utility having taken and continuing to take all reasonably available steps to mitigate the magnitude of its above-market electric power generation and supply costs;
>
> [N.J.S.A. 48:3-50.c.(4)].

N.J.S.A. 48:3-57 provides, among other things, that power procured for BGS shall be purchased at prices consistent with market conditions, and that utilities shall be permitted to recover on a full and timely basis "all reasonable and prudently incurred costs incurred in the provision of basic generation services..." N.J.S.A. 48:3-57.e.

As noted above, on July 31, 2002, Governor McGreevey signed Executive Order No. 25, creating the Deferred Balances Task Force, which was charged with examining the deferred balances the electric utility companies accumulated in implementing EDECA, and to provide a report addressing the reasons why they were accumulated, what mitigation steps were taken by the utilities to reduce the deferred balances and how they ought to be addressed to best protect the interest of ratepayers. In its final report, the Task Force noted that the BPU was conducting full evidentiary hearings on this issue, with participation by the RPA and other interested parties, as well as requiring an independent audit of the deferred balances. The Task Force strongly supported consumer protections to ensure that the burden of proof for recovering the deferred balances is placed squarely on the utility companies, and urged that the balances they claimed undergo the strictest of scrutiny.

Thus in performing its prudence review of the deferred balances, and in particular the deferred BGS balance, the Board is cognizant of its difficult responsibility to balance these competing interests, and will apply strict scrutiny to assess whether utility management made proper decisions and took proper actions, consistent with applicable legislative and other regulatory requirements, that a reasonable company should have made and taken, given the alternatives and information available at the time. In accordance with well-established principles of law, the Company must also bear the burden of proof to demonstrate the prudence of its actions and decisions.

2. BGS Procurement Performance

Contending that its energy purchases throughout the Transition Period were consistent with market conditions, the standard set forth in N.J.S.A. 48:3-57.a., ACE asserts that its BGS procurement was reasonable and prudent, and thus that its procurement costs are fully recoverable. (CIB at 16). Moreover, any determination that an expense was unreasonable or imprudent must be supported by facts in evidence, and no party, the Company avers, has provided evidence that any single transaction of the Company's was unreasonable or imprudent. (Reply Exceptions at 1,7). The Board must also be mindful of the legal standards under which it conducted the restructuring of the State's electric utilities, as set forth in EDECA, as well as the directives of the Final Restructuring Order on which the Company relied, and the Audit Report on which the ALJ placed extensive reliance. (*Id*. at 2). Citing N.J.S.A. 48:3-57.e., which states that utilities are to be allowed recovery of "all reasonable and prudent costs incurred in the provision of basic generation services," the Company asserts that the RPA and other parties have placed undue emphasis on "prudency," as opposed to "reasonableness." In light of an extensive evidentiary record assertedly demonstrating that it developed and implemented a responsible procurement process despite the uncertainties that accompanied the start of consumer choice, the Company argues that "before there is any disallowance of any BGS expense, the Board must make a finding that such expense was unreasonable." (emphasis in the original). (*Id*. at 7).

The other parties do not agree that ACE's BGS procurement was reasonable and prudent throughout the Transition Period, and assert that, by not availing itself of the risk mitigating options permitted by the Final Restructuring Order (parting contracts and hedging), and by mismanaging the RFP process, the only option the Company did pursue, the Company's BGS costs were unnecessarily and imprudently increased. Accordingly, the RPA and NJLEUC propose, and the Auditors have recommended, the following BGS disallowances:

Ratepayer Advocate[67]

- o $25.527 million of the cost of the Company's July and August 2001 third party energy purchases deemed excessive;

- o $3.375 million of excess capacity purchases assertedly re-sold at a loss; and

- o $3.528 million of BGS administrative costs for which the Company has assertedly not sustained its burden of proof, for a total of $32.430 million.

NJLEUC

- o one half of the Company's projected July 31, 2003 deferred BGS balance (a disallowance of $31 million based on actual data through May 2003) to more equitably apportion the consequences of Atlantic's asserted unreasonable and imprudent procurement practices.

Auditors' Recommendation

- o $6.119 million of increased costs attributed to the Company's failure to purchase the full 400 Mw of attractively priced capacity offered in response to RFP III.

Staff supported the third party purchase and excess capacity disallowances recommended by the RPA, as well as the Auditors' recommended disallowance, finding them warranted in light of the Company's poor performance compared to Staff's PJM benchmark and the achieved results of JCP&L and RECO. (SIB at 38-41).

Citing the Board's approval of the "portfolio approach" employed with Atlantic's RFPs, as well as the Company's arguments supporting the prudence of its BGS procurement, particularly its criticism of the RPA's quantification of the third party purchase disallowance, the ALJ rejected the disallowances proposed by the RPA and NJLEUC, and accepted the Auditors' recommended adjustment. (I.D. at 69; 72-73).

After carefully reviewing the extensive record, for the reasons discussed herein, the Board adopts the ALJ's recommendation to accept the Auditors' recommended adjustment, but rejects the balance of the ALJ's findings on the recommended BGS disallowances.

In considering the positions of the parties the Board must not only weigh how effectively or ineffectively ACE implemented and conducted the RFP process it was directed to pursue by the Final Restructuring Order, and the decisions it made after receiving the bids offered in response to those RFPs, but also whether it appropriately considered the parting contract option with the purchasers and potential purchasers of its generating assets. NJLEUC also raises the failure of

67 The RPA also proposed an additional reduction in BGS costs, the LEAC interest adjustment of $1.993 million discussed below, that is unrelated to prudence.

the Company to enter into a supply contract with CESI, its unregulated affiliate, as an issue. Whether the Company gave sufficient consideration to hedging, another risk mitigating option allowed by the Final Restructuring Order, must also be considered, as well as Staff's benchmark analysis that assertedly shows the Company did poorly compared to the PJM spot market and JCP&L and RECO. The Board notes that these utilities also divested their generating units, and thus faced many of the same challenges as the Company. Finally, we wish to emphasize that our approvals of the Company's requests to issue RFPs during the Transition Period were not approvals of the associated costs, but rather were consistently and explicitly predicated on the clear understanding that the recovery of the related costs would be subject to a review of their reasonableness and prudence.

(a) RFP Process

Although not necessarily intended to be the only source for the portion of Atlantic's BGS supply in excess of that obtainable from its NUGs and TBD generation during the first three years of the Transition Period, the Company was directed by the Final Restructuring Order to conduct an RFP process to obtain such supply:

> During the first three years of the Transition Period, up to and including July 31, 2002, ACE shall solicit requests for proposals ("RFP Process") for the provision of wholesale supply for BGS in twelve month pricing cycles, or such other cycles as ACE deems necessary or prudent. ACE will submit its plans for the RFP Process to the BPU by September 15, 1999. ACE shall commence the RFP Process as soon as practicable after such date and approval of the plan by the BPU, with the goal of concluding such process and entering into a contract for BGS supply by December 15, 1999. Any agreements for the provision of BGS shall be presented to, and subject to the approval of, the BPU.
>
> [Final Restructuring Order at 87, paragraph 7]

In brief, the Company issued five RFPs during this period. The first, RFP I, a "full requirements" RFP, was issued on October 9, 1999, and sought bids for the supply of the Company's entire BGS load not served by its NUGs and TBD generation for the period from January 2000 through July 2002. Due to the inability of potential suppliers to estimate what the Company's load would be over this period, given the uncertainties as to the dates its generating units would be divested, how many customers would elect to take service from third party suppliers, and potential buyouts of its NUG contracts, the full requirements RFP drew no responses. A revised version, RFP 1-A, was issued on October 27, 1999. Drawing on the feedback from the first RFP, varying amounts of energy and capacity were sought for the limited term of January through May 2000 on the assumption the Company's nuclear interests would be divested by then. However, only two responses were received. Both bids were judged to be more expensive than the PJM spot market, and thus were rejected, as were the bids received in response to RFP II issued on April 27, 2000, also on the expectation that the cost of PJM spot market purchases would be lower. In this RFP, Atlantic sought energy and capacity for the summer months (June through August) of 2000. Three-month, and at the behest of the Board, 12-month bids for 300 Mw, and an additional 350 Mw that would be needed if the nuclear units were divested, were sought.

A "portfolio approach" was adopted in issuing the next two RFPs, RFP III issued on October 30, 2000, and RFP IV issued on March 21, 2001. In RFP III, 400 Mw of capacity and varying amounts of on peak energy were sought for the period from January 2001 through July 2002. Of the 400 Mw of capacity sought, only 200 Mw was accepted by the Company. In view of its relatively attractive price, the Auditors found that the Company should have accepted the full 400 Mw, and recommended that the estimated additional cost of $6.119 million incurred from accepting only the 200 Mw be disallowed. Atlantic also accepted the lowest bid for the varying amounts of on-peak energy. In RFP IV, the Company sought 400 Mw of capacity for the period from June 2001 through September 2002, as well as 300 Mw per hour of on-peak energy and 300 Mw per hour of "super peak" energy to be supplied during the months of July and August 2001, and July 2002. The Company accepted two bids of 400 Mw each for capacity, and the single lowest bid for on-peak energy. The capacity and energy purchases made pursuant to these RFPs will be discussed in greater detail below, since they were largely responsible for the costs incurred in July and August 2001 that prompted the Advocate's recommended energy cost disallowance, and, throughout the period, for the capacity costs on which the quantification of the Advocate's excess capacity disallowance is based.

As discussed above, the Auditors found that ACE "did not have a full understanding of what the BGS process would entail and did not take adequate steps to establish an experienced BGS supply organization" at the outset of the transition period. (AUD-2 at VIII-23). While an outside consultant was retained in June 2000 to assist its staff, "[t]hroughout the first three years of the transition period ACE had limited in-house staff and did not have adequate analytical resources to consistently make effective decisions regarding BGS supply procurement." (*Id*. at VIII-25). As to the RFPs, the Auditors found that "ACE's actions with respect to RFP-1 were flawed, both in the development of the RFP itself, and in the analysis and decision making process regarding the results of the RFP." (*Id*. at VIII-27); that "RFP III was moderately successful, resulting in acceptable bids for energy and capacity." (*Id*. at VIII-32); and that "ACE's actions and decisions regarding RFP IV were reasonable." (*Id.* at VIII-33). While characterizing RFPs I and II as being "flawed," it was not clear to the Auditors that the deficiencies they found had a quantifiable cost impact. (*Id*. at I-12; VIII-56).

Echoing the Auditors' findings, the ALJ found that the "record contains no persuasive rationale for petitioner's failure to initially assemble an experienced BGS supply organization, in terms of both personnel and research. Compounding the situation was the fact that the staff assigned to energy procurement were not performing such functions on a full-time basis." (I.D. at 62). The ALJ also faulted the Company for failing to submit an RFP plan to the Board by the mandated September 15, 1999 due date: "…petitioner's failure to comply with the BPU's directive, and to advise the BPU of the reasons at the time, reflect some failure to effectively manage the procurement process." (*Id*. at 63). In view of the load uncertainties cited by the Company, it would have been "more reasonable for petitioner to seek more supply options vis-à-vis contracts, and it was unrealistic, at the time, to expect that other suppliers, given the uncertainties, would have bid for a full supply contract.", as argued by NJLEUC. (*Id*. at 62).

In contending that Atlantic's procurement process was flawed, the RPA cited a lack of competent staff as well as the Company's asserted failure to provide that staff with adequate resources, as evidenced by the Auditors' finding that the Company did not "routinely gather market intelligence on consummated forward contracts," nor did it "track and evaluate bilateral transactions in conjunction with independent projections of congestions cost risks." (AUD-2 at VIII-25) The Advocate also cited the Auditors further finding that "[a]lthough a Conectiv organization routinely projects PJM prices on a daily basis, this information is not provided to the individual responsible for BGS procurement," and that the Company did not use models or tools to implement its BGS procurement strategy, not did it routinely use a decision model to balance spot purchases with forward contracts. (AUD-2 at VIII-25 to VIII-26). (RPA Exceptions at 13-21).

In its Briefs and Exceptions NJLEUC cites many of these same factors in contending that the Company's procurement process was neither reasonable nor prudent throughout the Transition Period. While agreeing that the ALJ correctly pointed out the many shortcomings evident in the Company's BGS procurement process, Staff did not find them appropriately reflected in the ALJ's findings on the recommended BGS disallowances.

The Company nonetheless contends that no party provided evidence that would support a finding that any single transaction the Company made during the Transition Period was imprudent. It additionally asserts that there is no record evidence to indicate that either its early RFPs, or even its failure to file an RFP with the Board in September 1999, or its later RFPs resulted in any unreasonable or imprudent costs, including the costs the Company incurred in the summer of 2001. The Advocate responds by asserting that the burden of proof that the Company's actions, taken as a whole, were reasonable and prudent falls on the Company. Accordingly, the RPA does not have to demonstrate the imprudence of a single energy transaction. NJLEUC and Staff also emphasize the need to consider the actions of the Company and the results of its procurement process over the Transition Period as a whole. Moreover, the ALJ shares this view: "Petitioner, in part, argues that…no party points to any discrete decisions which were unreasonable, given the circumstances at the time. Such an approach, however, ignores the record as a whole and is inconsistent with the principle that the burden of proof is on the Company. I am persuaded by the argument of NJLEUC that the entire period must be viewed as a whole and by Crane's testimony in that regard." (I.D. at 61-62). Again in response to the Company's assertion that its having missed the Board's September 1999 deadline had no impact on costs, the ALJ states that: "Although, as petitioner argues, there is no clear nexus in the record to show that its failure to file for RFP approval in September 1999 had a direct relationship to any costs Ratepayer Advocate seeks to disallow, the point of the analysis of the intervenor, and the other parties, is that it is incumbent on petitioner to show that its procurement practices, overall, were reasonable, not for other parties to establish a direct causation link, which may be impossible." (*Id*. at 63-64).

We agree, and for the reasons stated above, find the Company's management of the RFP process during the first three years of the Transition Period to have been seriously deficient. Moreover, we find that even within the framework of the RFPs it did issue, the Company's decisions as to how much capacity and energy to accept, and in particular, for how long a term, provide additional support for the reasonableness of the recommended BGS disallowances, as discussed more fully below.

(b) Parting Contracts

In authorizing the use of this option in the Final Restructuring Order, the Board recognized that "parting contracts," whereby the buyer as part of a generation asset sale agrees to sell some or all of the energy, capacity and/or other services from the acquired units back to the seller for a limited period of time, could serve two basic purposes: they could be employed to enhance or make possible the sale of the divested assets, as stated in paragraph 20 on page 91, or, without implying that the two purposes are in any way mutually exclusive, they could serve to protect ratepayers from the "vagaries of the developing competitive energy market during the transition to competition," as stated on page 80. In defending its not having negotiated parting contracts with NRG at the time it agreed to purchase the Company's fossil units, or with the purchasers of its nuclear interests at the time of the nuclear sale, the Company cites the first of these purposes, and contends that for such a contract to have enhanced the sale of the divested assets it would have to have been negotiated at an above-market price. Had it been below market, as assertedly assumed by the parties who criticized the lack of a parting contract, "there is no doubt that this would have had an effect on the price that the purchaser was willing to pay, for either the nuclear or fossil units." (ACE Reply Exceptions at 14).

The RPA avers that had the Company availed itself of the parting contract and hedging options allowed by the Final Restructuring Order, it might have avoided the price spikes occurring in the summer of 2001. (Tr. 713-715).

NJLEUC is sharply critical of the Company's failure to use parting contracts as a means of securing firm supply at reasonable rates during the Transition Period. Citing as an example PSE&G's contract with its unregulated affiliate, PSEG Power LLC, for the supply of all of PSE&G's BGS requirement during the first three years of the Transition Period, NJLEUC contends that ACE should have entered into a similar supply arrangement with CESI, its unregulated affiliate, to which approximately 500 Mw of ACE's formerly-owned combustion turbine capacity was transferred. Noting that power delivered under PSE&G's BGS supply contract was priced at the production cost component of PSE&G's shopping credit, and therefore that PSE&G incurred no BGS deferral during the first three years of the Transition Period, NJLEUC recommends that Atlantic not be permitted to recover from its ratepayers more than its shopping credit for this 500 Mw of supply. (NJLEUCIB at 23-25). In re-iterating its criticism of the Company's failure to enter into a supply arrangement with CESI in its Reply Brief, NJLEUC asserts (at 6-7) that during 1999 and 2000, Atlantic's shopping credit exceeded the rates prevailing in the PJM wholesale marketplace at that time. "Therefore, had Atlantic structured a parting arrangement similar to PSE&G's, it cannot be said that [it] necessarily would have entailed sales at below-market rates."

NJLEUC also asserts that the Company's failure to have negotiated a parting contract contributed to the delay that ultimately led to the termination of the NRG sale. The lack of a parting contract became an issue early on, with the RPA arguing that its absence exposed Atlantic's customers to undue supply and price risks during the Transition Period. The Company responded by negotiating an "after the fact" PPA with an NRG affiliate for the purchase of 400 Mw and related energy for a term that would have extended from the closing date of the sale through August 31, 2002. The Advocate found the terms of this PPA unfavorable as compared to those of a parting contract negotiated by NRG and Delmarva Power & Light Company ("Delmarva"), another Conectiv utility subsidiary, in connection with an unrelated sale of generating assets.[68] According to ACE, the PPA was subsequently terminated "due to the passage of time." (NJLEUCIB at 25-27).

NJLEUC also briefly reviewed Atlantic's sale of its nuclear interests, again pointing out that initially ACE had not negotiated a parting contract for capacity and energy supply, but amended its filing to include the FSLO, which the Board found to be in the public interest. However, in approving the FSLO the Board emphasized that the Company had not been granted an "absolute right" to recover its deferred costs, and that replacement power costs incurred in serving BGS as a result of the nuclear sale "are, and shall continue to be, subject to Board review of the prudence and reasonableness of the Company's actions and resultant costs." (*Id*. at 27-28).

As noted above, the ALJ commented extensively on the Company's failure to negotiate a parting contract, observing that "[a]lthough there was an emphasis on the RFP process in the *Final Order*, the BPU clearly gave notice that other mechanisms should be considered, such as parting contracts..." (I.D. at 63). This guidance notwithstanding, the ALJ found "scant evidence in the record of consideration of parting contracts or other financial instruments for hedging purposes…Not only did petitioner fail to explain why parting contracts were not considered, the record does not evidence why its affiliated service company was not utilized." (*Id*.). Moreover, such analysis as the Company did perform was found wanting: "Although petitioner's analysis regarding the probability of parting contracts may have some merit in general, the lack in the record of attempts to negotiate parting contracts, and the fact that petitioner expressly did so at the behest of the BPU, supports the arguments of the other parties." (*Id*. at 67). With respect to NJLEUC's arguments, the ALJ gave weight "to the fact that the record does not indicate why petitioner did not attempt to negotiate a parting contract with CES, to which the Company's CTs, which had capacity exceeding 500 MW, were transferred at net book value, which, as NJLEUC argues, would have reduced the need to make an equivalent purchase in the spot market...Although the 500 MW of supply from the CTs would not have put petitioner in a position to avoid any acquisitions in the spot market, it may have mitigated the result of the price increases occurring in the summer of 2001." (*Id*. at 64). The ALJ was also "persuaded, to an extent, by NJLEUC's analysis that, in light of the fact that the shopping credit rate was above

[68] However, the Board's Order approving the NRG sale (the February 20, 2002 Order *supra* in Docket No. EM00020106) indicates that the Delmarva assets, although not subject to the Board's jurisdiction, were included as part of the sale under discussion.

rates prevailing in the PJM wholesale market during 1999 and 2000, parting contracts might have been considered if the shopping credit were used as the benchmark rate. In addition, the fact that NRG did ultimately enter a parting contract agreement raises questions as to why petitioner did not explore such options earlier." (*Id*. at 68).

Considering first NJLEUC's contention that Atlantic should have negotiated a supply arrangement with CESI similar to that entered into by PSE&G with its unregulated affiliate, the Board notes that the Final Restructuring Order did allow a competitive affiliate to bid to provide wholesale supply for ACE's BGS during the Transition Period, subject to the affiliate complying with affiliate relations standards then to be adopted by the Board. (Final Restructuring Order at 89, paragraph 13). Additionally, subject to abiding by similar safeguards, Atlantic was authorized by paragraph 10 on page 88 to utilize its affiliated service company to make arrangements for BGS supply pursuant to paragraphs seven through fourteen. Beyond giving the Company the ability to do so, however, the Final Restructuring Order did not contemplate a supply arrangement for ACE similar to that approved for PSE&G with its unregulated affiliate. Moreover, as the Company points out, that contract "was part of the larger resolution of the PSE&G case [restructuring proceeding], and can't be viewed in isolation."[69] (CRB at 8) Thus while it could be argued, as NJLEUC does, that the Company should have pursued this option, we do not believe its failure to do so rises to the level of imprudence.

On the other hand we find NJLEUC's point about Atlantic's relatively high shopping credits well taken, agreeing that a parting contract priced at Atlantic's shopping credits might well have been attractive to the purchasers of its generating assets at the time the agreements of sale were executed. Moreover, Atlantic's shopping credits were higher than PSE&G's:[70] 5.27 cents per kwh and 5.31 cents per kwh in 1999 and 2000, respectively, as compared to PSE&G's shopping credits of 4.95 cents and 5.03 cents.[71] In 1997 and 1998 there was also an expectation that prices would go down, not up, as a result of competition in the energy marketplace. Indeed, one of the primary goals of the EDECA enacted in February 1999 was, by fostering competition, to

[69] Pursuant to the Board's Final Order in PSE&G's restructuring proceedings, all of PSE&G's generation assets were transferred to its unregulated affiliate, PSEG Power LLC, at an administratively determined market value that was substantially less than book value. Of the $2.9 billion difference, net of tax, approximately $0.5 billion was recovered from PSE&G's ratepayers during the Transition Period, and the balance was securitized over 15 years, with the repayment of the interest, principal and related income taxes included in PSE&G's TBC and MTC-Tax. (*I/M/O Public Service Electric and Gas Company's Rate Unbundling, Stranded Costs and Restructuring Filings*, Docket Nos. EO97070461, EO97070462 and EO97070463, Final Order dated August 24, 1999 at 118, paragraph 10).

[70] Atlantic's floor shopping credits, shown on page 96 of the Final Restructuring Order, were the highest in the State. PSE&G's shopping credits are shown on page 121 of the Board's Final Order in PSE&G's restructuring proceedings *supra*.

[71] The parting contract price would be for the energy and capacity component of the shopping credit only. After eliminating the 6% New Jersey Sales and Use Tax, transmission charges and other non-production related costs, the Company's response to RAR-MTC-23 indicates this component would be about 1.5 cents lower than the shopping credit.

lower the high cost of energy in the State. (N.J.S.A. 48:3-50.a.(1) and (2)). This expectation in turn would provide an incentive for the purchasers of the Company's generating assets to consider a parting contract to protect against falling prices, as well as to provide an assured revenue stream for the purchased assets, especially the nuclear assets, as the competitive market matured. While the same expectation might be taken into account by the seller in considering the length of the contract, balancing that consideration is the paramount objective of minimizing market risk by obtaining the physical hedge a parting contract would provide. Apart from the question of its length, what would now be viewed as a "below market" contract as compared to current energy prices could well have been perceived as being "above market" at the time the generating assets were sold, and thus readily available, given the substantially lower energy prices that prevailed then.

That long-term parting contracts, or contracts otherwise tailored to the needs of the seller could be executed at attractive ("below market") rates at that time is borne out by the experience of the State's two other similarly situated utilities, JCP&L and RECO.

On October 15, 1998, JCP&L executed an agreement to sell its 25%, 196 Mw ownership in the 786 Mw TMI-1 nuclear unit to Amergen, a partnership formed by PECO Energy Company ("PECO") and British Energy PLC. JCP&L petitioned the Board for approval of the sale on December 11, 1998, which was granted by the Board's Summary Order in Docket No. EM98121409 dated December 15, 1999.[72] The sale closed on December 20, 1999, and under the associated Transition Power Purchase Agreement ("TPPA"), JCP&L began purchasing its share of TMI-1's energy and capacity on that date for a term extending through December 31, 2001 at bundled energy and capacity rates ranging from approximately $27 per Mwh to $30 per Mwh.[73]

On November 24, 1998, RECO's parent company, Orange and Rockland Utilities ("O&R"), executed a Transition Power Sales Agreement ("TPSA") with the purchaser of its generating assets, Southern Energy Affiliates, that provided the O&R system with 940 Mw of capacity through April 30, 2000 and 600 Mw through October 2000, as well as on and off-peak energy from November 1, 1999 through April 30, 2000.[74] Energy deliverable under the TPSA was priced at $26 per Mwh, and capacity at $130 per Mw-day.

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[72] In Docket No. EM98121409, *I/M/O the Verified Petition of Jersey Central Power & Light Company, d/b/a GPU Energy, Seeking Approval of the Sale of the Company's Interest in the Three Mile Island Unit 1 Generating Facility Pursuant to N.J.S.A. 48:3-7, a Specific Determination Allowing the Three Mile Island Nuclear Generating Facility to be an Eligible Facility Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and a Waiver of the Advertising Requirements of N.J.A.C. 14:1-5.6(b)*. A final Order was issued on March 4, 2003.

[73] Exhibit S-36, Docket No. ER02080507 *supra* (JCP&L's deferred balances proceeding).

[74] Additional energy up to the full requirement of O&R's system was supplied under another agreement, the Incremental Energy Sales Agreement ("IESA") executed with affiliates of Southern Energy Affiliates on June 14, 1999. The IESA was intended to bridge the gap between the time O&R's generating units were divested and the time the former New York Power Pool began operating as an

On October 15, 1999, JCP&L entered into an agreement to sell its 619 Mw Oyster Creek nuclear unit to AmerGen and petitioned the Board for its approval on December 13, 1999. The sale was approved by the Board's Summary Order in Docket No. EM99120917 dated July 28, 2000,[75] and closed on August 8, 2000. On that date, JCP&L began purchasing the Oyster Creek energy and capacity for a 32-month term that extended through March 31, 2003 at bundled energy and capacity prices ranging from $33 per Mwh to $36 per Mwh. (Oyster Creek Order at 3).

Atlantic's agreement to sell its nuclear interests to the majority co-owners, PSEG Power LLC and PECO, was executed on September 27, 1999, less than a month before JCP&L entered into its agreement with AmerGen. On November 23, 1999, Atlantic petitioned the Board for approval of the sale, which did not provide for a parting contract. On May 4, 2000, the Company amended its filing to include the FSLO, a call option based on the difference between the around-the-clock average LMP at PJM's Salem bus and strike prices of $40 per Mwh in June 2000, $60 per Mwh in July, and $55 per Mwh in August. If the average LMP exceeded the strike price, the difference, applied to 350 Mw at a 100% capacity factor (252 Gwh in June and 260.4 Gwh in July and August) was to be paid the Company by the grantor of the option, PSEG Energy Resources and Trade, LLC. The FSLO also provided for the Company to purchase 372 Mw of unforced capacity at $60 per Mw-day in the months of June through August 2000.[76] The sale was approved by the Board in its Order in Docket No. EM99110870 dated July 21, 2000 *supra*.

While better than nothing, the FSLO fell far short of the parting contract JCP&L negotiated with AmerGen, which also had PECO, one of the two majority co-owners that purchased the Company's nuclear interests, as one of its partners.[77] Moreover, the FSLO was not extended[78]

Independent System Operator, and thus was in effect from June 30, 1999 through November 18, 1999. (See *I/M/O the Verified Petition of Rockland Electric Company for the Recovery of its Deferred Balances and the Establishment of Non-Delivery Rates Effective August 1, 2003*, Docket No. ER02080614, Order dated April 20, 2004 at 34.)

75 *I/M/O the Verified Petition of Jersey Central Power & Light Company, d/b/a GPU Energy, Seeking Approval of the Sale of the Oyster Creek Nuclear Generating Station Pursuant to N.J.S.A. 48:3-7, a Specific Determination Allowing the Oyster Creek Nuclear Generating Station to be an Eligible Facility Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and a Waiver of the Advertising Requirement of N.J.A.C. 14:1-5.6(b)*. ("Oyster Creek Order"). A Final Order was issued on November 21, 2003.

76 July 21, 2000 Order *supra* at 21.

77 That PECO might have been amenable to a long-term, attractively priced parting contract is evidenced by the pre-Transition Period PECO purchase noted previously, which began on March 20, 1998 and continued through May 31, 2000 (Atlantic's response to RAR-MTC-22). Under this PPA, Atlantic purchased 125 Mw at $125 per Mw-day, and 571 Gwh of energy at an average cost of $23.41 per Mwh. The average cost of energy and capacity was $31.75 per Mwh over the contract term. (Schedules 1(c), 1(d) and 1(e), Schedule JAE-1 Revised attached to P-8).

as part of the virtual sale agreement Atlantic entered into with the majority co-owners on October 7, 2000, pending the Board's issuance of a second order in the nuclear sale docket making a preliminary determination of the recovery-eligible stranded costs of Atlantic's nuclear interests. As noted above, during the virtual sale period the purchasers of the nuclear interests received an entitlement to the capacity and energy from the units in return for reimbursing Atlantic for the units' operation and maintenance costs, including fuel, and capital expenditures. However, Atlantic's ratepayers bore, via its inclusion in the MTC, the return requirement on Atlantic's investment in the virtually sold units at 13.0% pre-tax, and in the absence of a parting contract, Atlantic was dependent for replacement power through July 31, 2002 on its third party purchases, the PJM spot market, and to a lesser extent its retained generating units at an average cost of $82.49 per Mwh after the virtual sale as compared to $46.50 per Mwh prior to the virtual sale.[79]

In sum, as NJLEUC points out, Atlantic did not even consider the parting contract option until prodded by others. By its actions the Company demonstrated that it was indifferent to the critical need of protecting its ratepayers, once the assured supply from its TBD units at a known cost would no longer be available. Relative to the parting contracts negotiated by JCP&L and RECO, we find that the Company's performance fell far short. Finally, we observe that, by establishing a firm date through which either its TBD generation would be available directly by virtue of being retained, or available indirectly via the parting contract, a parting contract would have eliminated the uncertainty as to the timing of the divestiture of the Company's generating units that complicated its RFP process.

(c) Financial Instruments (Hedging)

In authorizing the use of financial instruments to decrease ratepayer exposure to price spikes and volatility, the Board recognized that the use of such products could result in costs in excess of the spot market. To the extent reasonably and prudently incurred, however, such costs would be recoverable pursuant to N.J.S.A. 48:3-57.e. (Final Restructuring Order at 88, paragraph 11). The RPA and NJLEUC accordingly fault the Company for not having pursued this option, *i.e.*, hedging, as a means of mitigating the price spikes that occurred in the summer of 2001. The Company indicates that it did, however, consider hedging products other than a fixed price contract in early 2001, and concluded that the fixed price contract was the superior

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[78] While richly priced, if extended, the FSLO would have had definite value in mitigating the price spikes that occurred in the summer of 2001, as discussed below.

[79] As shown in Schedule 1(a) attached to JAE-1 (Revised). In the months of August 1999 through September 2000, the revenue requirement of the TBD units was $290 million and they generated 6,233 Gwh for an average cost of $46.50 per Mwh. In the months of October 2000 through July 2002, *i.e.*, in the months following the virtual and actual sales of Atlantic's nuclear interests, the revenue requirement of Atlantic's TBD units was $321 million and they generated 3,895 Gwh, for an average cost of $82.49 per Mwh. For the three years ended July 31, 2002, the revenue requirement of the TBD units was $611 million and they generated 10,128 Gwh (10,123 Gwh in Schedule JAE-1) for an average cost of $60.34 per Mwh.

alternative. (P-8 at 11). Additionally, as part of the analysis supporting the Company's decision to reject the offers it received in response to RFP II, the Company requested its consultant, Lexecon, to investigate the possibility of purchasing energy hedging products for the summer of 2000. Lexecon concluded that such purchases would not be appropriate, *i.e.*, worth the premium demanded relative to prior experience in the market place. (RA-12, letter dated June 9, 2000 from Jeffrey Tranen of Lexecon, Inc. to David G. Bacher of Conectiv Power Delivery).[80] Lexecon's hedging analysis was discussed again during the cross-examination of witness Elliott, who stated that the Company did not use call options because they were not economic. Thus, the Company employed fixed price contracts to hedge its price risk, especially in the peak energy market. (Tr. 210-213).

In view of the poor results achieved by RECO with its hedges,[81] and the limited use of financial instruments by JCP&L,[82] we concur with the Company's assessment, and accordingly find that the Company's decision not to employ financial instruments during the Transition Period was reasonable and prudent.

(d) Valuation Benchmarks

As discussed above, based on its review of the record, Staff supported the RPA's proposed third party purchase and excess capacity disallowances as well as the Auditors' recommended BGS disallowance. As a further check to assess the reasonableness of the Company's BGS performance during the Transition Period, Staff compared the cost of the Company's "discretionary purchases," meaning the cost of the capacity and energy it purchased from third parties, principally through RFPs III and IV, and from the PJM spot market, to the cost of obtaining the same capacity and energy from the PJM spot market alone. Staff also compared the cost of Atlantic's discretionary purchases to JCP&L's and RECO's. In making the comparisons, the cost of capacity and energy purchases made under PPAs with NUGs and, with the exception of parting contracts, PPAs entered into with other utilities prior to the Transition Period were excluded. Parting contracts were included in recognition of the fact that all three utilities had divested all or some portion of their generating assets, and thus could have chosen or not chosen to have entered into a parting contract with the purchasers of the divested assets. This analysis showed that the cost of Atlantic's discretionary purchases was $165 million higher than the cost of purchasing the same capacity and energy from PJM ($519 million from Schedule JAE-1 (Revised) attached to P-8, compared to $354 million calculated in Appendix SIB-2 attached to Staff's Initial Brief). When priced at the achieved cost of JCP&L's and RECO's discretionary purchases (from Appendix SIB-3 attached to Staff's Initial Brief), the

80 Although RA-12 is marked Confidential, the June 9, 2000 letter wasn't considered confidential, as indicated in the discussion *supra*. (Tr. 210-213).

81 In disallowing one half of RECO's hedging costs in RECO's deferred balances proceeding, the Board found the 55% premium RECO paid on virtually all of its hedges at prices as high as $164 per Mwh to be excessive. (April 20, 2004 Order in Docket No. ER02080614 *supra*, at 42-43).

82 As indicated on page 2 of Exhibit 3 attached, of the $2.233 billion expended by JCP&L on its discretionary BGS purchases, only $14 million, or less than 1%, was spent on financial instruments.

cost of the Company's discretionary purchases exceeded JCP&L's and RECO's by $163 million and $122 million, respectively.

After eliminating the pre-Transition Period (March 1998) PECO purchase inadvertently included in Staff's initial analysis, and making a similar adjustment to JCP&L's discretionary purchases, a revised analysis indicates that the cost of the Company's discretionary purchases exceeded the cost of equivalent PJM purchases by $177 million, and the cost of JCP&L's and RECO's discretionary purchases by $158 million and $135 million, respectively. The costs per Mwh and purchases on which the revised analysis is based are shown in Exhibit 3 attached. As shown there, in percentage terms the average cost of Atlantic's discretionary purchases, at 7.59 cents per kwh, was about 46% higher than JCP&L's average cost of 5.20 cents, and about 37% higher than RECO's average cost of 5.54 cents. While the Board recognizes that there are inherent differences among utilities, and while not suggesting that ACE should have relied solely on the PJM spot market, nonetheless, we believe that the magnitude of ACE's excessive costs relative to the costs achieved by the State's two other similarly-situated utilities who utilized parting contracts, appears unreasonable, and indicative of the shortcomings in the Company's BGS procurement identified by the parties herein.

We accordingly find that the ALJ erred in failing to consider Staff's analysis. In rejecting Staff's PJM benchmark analysis, the ALJ stated that:

> Staff's analysis in its initial brief comparing costs under petitioner's contracts for BGS supply to the costs to purchase from PJM without a contract was not subject to cross-examination. In fact, this judge denied a discovery motion made on behalf of Staff, for the first time, on the first day of hearings, Staff indicating that it was requesting the information because the Auditors had not done such an analysis. The appropriate way for such to have been presented was for Staff to either present witnesses or develop such through cross-examination of other parties' witnesses, not an approach which circumvents denial of a discovery request. In addition, petitioner raises meritorious concerns regarding Staff's analysis, on its face, which is based on the assumption of large amounts of BGS supply purchased at available PJM rates in a market that would not have been affected by large-scale purchases. Additionally, the analysis also apparently utilized price data outside ACE's zone in PJM. Without going into detail, petitioner presented an analysis[83] indicating that any such differences would have been smaller than that calculated by Staff, which calculations approximate, in number, ultimately, Ratepayer Advocate's adjustment.

[83] An apparent reference to the analysis the Company indicated it had prepared in its Reply Brief (at 9).

[I. D. at 67-68]

The ALJ also rejected Staff's analysis comparing Atlantic's costs to JCP&L's and RECO's, citing the reason she gave for disregarding NJLEUC's use of PSE&G's BGS contract with its unregulated affiliate to support NJLEUC's contention that Atlantic should have negotiated a similar arrangement with its unregulated affiliate: "The facts pertinent to PSE&G are not detailed in the record, and each case must be based on the facts specific to the utility in question."

Addressing first the ALJ's concern that Staff's analysis was not subject to cross-examination or sponsored by a Staff witness, this issue also arose in a 1989 base rate case filed by New Jersey Natural Gas Company,[84] in which the presiding ALJ did not consider Staff's proposals because they appeared for the first time in Staff's brief. In disagreeing with the ALJ, the Board found that the ALJ's conclusion

> is premised upon a misunderstanding of the role of Staff. Staff's role in a rate proceeding is to analyze the evidence submitted by the parties on the basis of its expertise and understanding of Board policy, make recommendations on the basis of such analysis, and make those recommendations available to the parties and to the ALJ. "There is no obligation on the part of Staff to present direct evidence prior to taking a position." <u>Public Advocate Dep't v. Public Utilities Board</u>, 189 <u>N.J</u>. <u>Super</u> 491, 518 (App. Div. 1983). When Staff made its recommendations to the Board, on the record in the form of a brief and later by exceptions to the ALJ's recommendation, it "did what it was supposed to do." <u>Id</u>.
>
> The ALJ's reliance upon <u>N.J.S.A</u>. 52:14B-9(c) is misplaced. All parties had an opportunity to respond to Staff's positions in their reply briefs and in replies to exceptions. Furthermore, <u>N.J.S.A</u>. 52:14B-10(b) affirmatively permits an agency to utilize the expertise of its staff provided that such expertise is disclosed on the record.
>
> [July 17, 1990 NJN Order at 4-5].

Moreover, in that same Order, and while stressing that no party may introduce new facts into the record by way of post-hearing submissions ("A final decision must be based only upon evidence of record at the hearing"), the Board found that "an agency is free to accept the post hearing analysis of its Staff "[s]o long as the final order of the agency has a basis in the record."

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84 Docket No. GR89030335J, *I/M/O the Petition of New Jersey Natural Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions*, Order dated July 17, 1990 ("July 17, 1990 NJN Order").

Public Advocate Dep't v. Public Utilities Board, 189 N.J. Super. 491, 519-20 (App. Div. 1983). Therefore the Board REJECTS the ALJ's narrow view of the role of Board staff at rate hearings." (*Id*. at 5).

We note that in this case, Staff's analysis was presented in its Initial Brief, and that the parties had an opportunity to respond thereto. We additionally find it to be consistent with Staff's obligation to insure that the Board has as complete a record as possible on which to base its decision. Moreover, Staff proffered its analysis for the purpose of establishing a yardstick by which the cost of the Company's asserted failure to have managed its BGS procurement effectively could be measured. For this purpose, we find the costs achieved by the State's two other similarly-situated utilities, both of which executed parting contracts with the purchasers of their divested generation assets, as well as the PJM spot market, appropriate. We also note that EDECA requires that BGS supply be acquired consistent with market conditions, and that there are other markets apart from the third parties relied upon by the Company, the most obvious being the energy and capacity markets administered by PJM. Accordingly, we find that the ALJ erred in failing to consider Staff's comparative analysis, all of which has been submitted in the record or references publicly available information on file with the Board.

In its Reply Brief the Company expressed several substantive concerns with both Staff's PJM benchmark analysis and its comparison of the Company's contract costs to those of JCP&L and RECO. As indicated above, the ALJ found the Company's concerns with Staff's PJM analysis (its use of a PJM rate outside the ACE zone and its assumption that PJM's prices would not be affected by ACE's increased PJM purchases in lieu of contract purchases) "meritorious."

With respect to the price issue, Staff used PSE&G's Zonal LMPs in lieu of Atlantic's, which as noted above, the Auditors' were unable to obtain from the Company. The Company asserted that it had "prepared its own analysis of Staff's approach, which is being provided under separate cover.[85] Using PJM prices for Atlantic's service territory, the difference is much less than that found by Staff for the time period in question. While there is still a difference, as Atlantic has already [stated] above it simply cannot be assumed that the Company could have used the PJM market instead of contracts for BGS supply." That, the Company contended, would have had an impact on the historical PJM prices employed in Staff's analysis.[86]

In contending that Staff's comparison of the average cost of Atlantic's contract purchases to those of JCP&L and Rockland was invalid, the Company asserts that "those two companies purchased all of their BGS supply needs through such contracts, while Atlantic only used contracts to meet the supply needs over and above what was available from the retained

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[85] This analysis was apparently never entered into the record.

[86] With respect to the PJM zonal pricing issue, Staff advises the Board that it had also performed its benchmark analysis using the then GPU System billing rates on file with the Board, *i.e.*, the rates at which JCP&L's PJM purchases could have been made during the Transition Period, and found no significant difference in the results. Staff also recalculated the PJM benchmark using the on-peak LMPs shown in Appendix SIB-2 to quantify the difference between an average and an on-peak comparison. This reduced the excess cost of Atlantic's discretionary purchases from $177 million to $87 million.

generation and the NUGs…In essence, Staff is comparing JCP&L and Rockland's cost to serve all of their BGS load (the base and the portion that varied over the transition period) with Atlantic's cost to serve the variable portion only." (CRB at 9-10).

As to this assertion, *i.e.*, that it is inappropriate to compare Atlantic's cost to serve just the variable portion of its load to JCP&L's and RECO's cost to serve all of their BGS load, including the base component, we first note that the Company's assertion that these two companies "purchased all of their BGS supply through third-party contracts (including base load supply)" (Reply Exceptions at 15; CIB at 9) is not correct. In RECO's case, a small portion of its BGS energy requirement (about 4%) was obtained from NUGs during the first three years of the Transition Period, and the balance was obtained from parting contracts and the NYISO and PJM spot markets. In addition to NUGs and the PJM spot market, JCP&L's BGS requirement was obtained from parting contracts, two-party purchases and its to-be-divested generation. Moreover, as discussed in more detail below, Atlantic's contract purchases do, in fact, include a substantial "base load" component, namely 300 Mw purchased "around the clock" from Reliant Energy in the months of January through July 2002. This purchase represents approximately 24% of Atlantic's total discretionary purchases,[87] which is not that much lower than the percentage the TPPAs (the base load parting contracts negotiated with the purchasers of JCP&L's nuclear units) are of JCP&L's discretionary purchases (about 30%).[88] Moreover, if only the cost per Mwh of Atlantic's post-Transition Period contractual third party purchases is compared to the cost of the comparable JCP&L purchases, the cost of Atlantic's contractual purchases exceeded JCP&L's by approximately $94 million.[89] As discussed below, a further analysis of just the on-peak component of Atlantic's third party purchases shows an even greater excessive cost as compared to the cost of the Company's own PJM purchases.

Finally, to put the BGS disallowances we have accepted herein in perspective, the Board notes that the approximate $35 million of disallowances (the RPA's proposed third party purchase and excess capacity disallowances as well as the disallowance recommended by the Auditors) represents about 7% of the cost of Atlantic's $501 million of discretionary purchases, and less than 2% of the cost of its BGS supply from all sources of $1.853 billion incurred during the first three years of the Transition Period. (Exhibit 3 attached).

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87 1,561 Gwh from Schedule 1(c) attached to JAE-1 (Revised) divided by the sum of "Other Contracts" and "PJM Markets" purchases of 7,168 Gwh from JAE-1 (Revised) less the pre-transition PECO purchase (571 Gwh from Schedule 1(c)).

88 12,913 Gwh divided by 42,969 Gwh, from Exhibit 3, pages 1 and 2.

89 3,385 Gwh times ($87.86 per Mwh – $60.06 per Mwh), where $60.06 = $1.125 billion divided by 18,735 Gwh, from Exhibit 3, page 2. The $60.06 per Mwh does not reflect the Board's disallowance of $329 million ordered in JCP&L's deferred balances proceeding. (Order dated May 17, 2004 *supra*, in Docket No. ER02080507 at 117-127; Exhibit 2). The $329 million disallowance was offset by $176.5 million of estimated savings from JCP&L's TPPAs and a NUG PPA renegotiation, for a net disallowance of $152.5 million.

(e) The Board's RFP Approvals

In the Summary Restructuring Order issued on July 15, 1999, and in subsequent orders approving the sale of the Company's nuclear interests and its RFPs issued throughout the Transition Period, the Board made it abundantly clear that the recovery of costs incurred in providing BGS would be subject to a Board review as to the reasonableness and prudence of those costs:

- o In modifying paragraphs 27, 28 and 29 of the June 9, 1999 Stipulation of Settlement, the Board stated that "final approval of recoverability of the Deferred Cost balance [the aggregate NNC, BGS and MTC balance, as well as the SBC balance via its inclusion in paragraph 35] is subject to Board review and reasonableness of such costs." (July 15, 1999 Summary Restructuring Order in Docket Nos. EO97070455 *et al.*, *supra*, at 6-7).

- o In approving the FSLO negotiated with PSEG Energy Resources and Trade, LLC, the Board stated that "the Company has not been granted an "absolute right" to recover its "Deferred Costs" balance and such purchase power replacement costs associated with sale of its interest in its Nuclear Assets for the purposes of serving BGS customers are, and shall continue to be, subject to Board review of the prudence and reasonableness of the Company's actions and resultant costs." (July 21, 2000 Order in Docket No. EM99110870, *supra* approving the sale of the Company's nuclear interests, at 21-22).

- o In denying the Company's requested pre-approval of the outcome of RFP II, the Board stated that it:

  > will not pre-approve an unexecuted contract as prudent. The Board has a long held practice of "after the fact" supply purchase prudency reviews. The Company has not demonstrated why the Board should change this practice by pre-approving its contracts. Nothing in the EDECA prohibits the Board from continuing such post supply purchase prudency reviews or warrants such a change in policy. Atlantic must, as other energy utilities must, develop and maintain an expertise regarding purchase strategies for its BGS service. Atlantic must justify any decisions it makes for obtaining energy and capacity for its BGS customers in an appropriate future ratemaking proceeding and show that they are prudent and reasonable.
  >
  > [May 15, 2000 Order in Docket No. EM00030156, *supra* at 4-5]

- o In authorizing the Company to proceed with the incremental 350 Mw it sought in RFP II, the Board stated that "Atlantic has not been granted an "absolute right" to recover its "Deferred Cost" [footnote omitted] balance, and such costs are, and shall continue to be, subject to Board review of the prudence and reasonableness of the Company's actions and the resultant costs." (May 30, 2000 Order in Docket No. EM00030156, *supra* at 3).

- o In approving RFP III, the Board stated that "[i]t will continue to be incumbent upon the Company to demonstrate, in an appropriate future proceeding, the reasonableness and prudence of its decisions in deciding to accept or not accept bids it may receive as the result of issuing the proposed RFP, as well as the flexible portfolio approach recommended by the Company's consultant." (November 29, 2000 Order in Docket No. EM00080604,[90] at 3).

- o In approving RFP IV, the Board stated that "it will continue to be incumbent upon ACE to demonstrate, in an appropriate future proceeding, the reasonableness and prudence of its decisions in accepting or not accepting bids it may receive as the result of issuing the proposed RFP." (April 27, 2001 Order in Docket No. EM01030162, *supra* at 3).

Moreover, with respect to the consultations on RFPs III and IV held with the Board's Staff and the Advocate, as described at 10 and 17-19 of P-8, during cross-examination witness Elliott acknowledged that the amounts requested and accepted pursuant to these RFPs were the Company's decision alone:

> Q. But in the end, would you agree it was the Company's decision
> …whether to accept or not accept the contract…?
>
> A. Yes.
>
> Q. Again, would you agree that it was the Company's
> decision alone to accept or not accept capacity
> contract entered pursuant to these RFPs?
> .
> A. Yes.
>
> Q. Were the amounts requested and accepted pursuant
> to the RFP decision of the Company alone?
>
> A. Yes.
>
> [Tr. 344-346]

90 *I/M/O the Petition of Atlantic City Electric Company for Approval to Issue a Request for Proposals, to Conduct a Competitive Procurement Process and to Enter into Agreements for the Supply of Basic Generation Service.*

Finally, in recognizing that the Company may have had to defer recovery of some portion of its BGS, NNC and MTC costs in order to achieve the rate reductions it was directed to implement during the Transition Period, the Final Restructuring Order, at 93, paragraph 27, authorized deferred accounting for these costs, and stated that "[a]ny Deferred Costs, together with a return on the unrecovered balance, will be audited by the Board and will be recoverable at the end of the Transition Period in a manner and timeframe to be determined by the Board."

It is clear from the above that the Board's approval of the Company's RFPs was consistently given with the full understanding that the resultant costs would ultimately undergo a prudence review, as undertaken herein. Thus the ALJ's reliance, at least in part, on the Board's approval of the portfolio approach followed in RFPs III and IV as a reason for rejecting the RPA's recommended third party purchase disallowance is misplaced.

3. Third Party Purchases, July/August 2001

Contending that the Company might have avoided the high cost of the third party purchases it made in July and August 2001 if it had entered into long-term purchase power contracts in 1999, or hedging arrangements to protect against excessive price spikes, as envisioned by the Final Restructuring Order, the RPA recommends that $25.527 million of the $64.312 million total cost of these purchases be disallowed. As shown in Schedule ACC-4 attached to RA-2, the disallowance was quantified by taking the difference between the actual cost of the third party purchases in these two months (an average of $119.45 per Mwh) and the cost of Atlantic's NUG energy and the revenue requirement of its TBD generation (an average of $72.00 per Mwh), and applying it to the 538 Gwh of energy purchased from third parties in the two months. In these months alone, the Company's deferred BGS balance increased by $78 million, prompting the RPA to assert that the Company's entire deferred BGS balance of $49 million, as projected in the initial filing,[91] might have been avoided if it had managed its costs better in just these two months. (RA-2 at 17-19; RIB at 19-20).

ACE argues that the assumption it could have obtained, in 1999, a contract that would have mitigated the cost of energy in July and August 2001 was contradicted by the outcome of its full requirements RFP. Of the 80 potential suppliers who received the RFP, none was willing to bid in view of the uncertainty as to when ACE's generating units would be divested and how many of its customers would switch to third party suppliers. In addition to this volume risk, potential suppliers faced equally uncertain and volatile energy and capacity prices, especially the latter due to still evolving PJM rules. Nor in the Company's view was the RPA's quantification appropriate, based as it was on a comparison of the market price of on-peak summer energy to the cost of serving base and intermediate load year round, *i.e.*, to the average cost of the Company's NUG power and embedded TBD generation. Instead, the Company maintained that the comparison should be to another source of more economic on-peak summer energy it could have acquired, but didn't. As evidenced by her responses to the Company's discovery, RPA

[91] The projected BGS balance as of July 31, 2003 based on actual data through June 2002, as shown in Schedule HAC-10 attached to P-11. The $78 million increase in the BGS deferral that occurred in July and August 2001 is shown in Schedule HAC-1.

witness Crane performed no analysis of market prices, market conditions, or contracts signed by other market participants that could lead to a finding of imprudence on the Company's part. Nor should the Company be punished for not making an RFP filing in September 1999, in that any defect arising from the failure to make such a filing was assertedly cured by the filing of RFP II in March 2000. (P-8 at 3-14).

While it did not address the RPA's recommended disallowance, NJLEUC proposes to disallow one-half of ACE's deferred BGS balance to "more equitably apportion the consequences of Atlantic's unreasonable and imprudent BGS procurement practices." (NJLEUCIB at 5; NJLEUCRB at 10). Based on the $49 million balance projected in the initial filing, $24.5 million would be disallowed; if applied to the projected balance of $62 million after updating to reflect actual data through May 2003, $31 million would be disallowed.

Staff supports the RPA's proposed disallowance, finding it warranted in light of the Company's poor performance when measured against Staff's PJM benchmark and the achieved results of RECO and JCP&L. (SIB at 38-41).

Citing the Board's approval of the Company's "portfolio approach" (the approach employed in RFPs III and IV), as well as the Company's arguments, and in particular its criticism of the Advocate's quantification, the ALJ rejects both the RPA's and NJLEUC's proposed disallowances. (I.D. at 69; 73).

As ACE notes on pages 8-9 of P-8, the energy purchases made under RFP III and RFP IV largely account for the cost of the third party purchases at issue. Pursuant to RFP III, on November 30, 2000, the Company executed a forward contract for the purchase of 400 Mw per hour of on-peak energy for July and August 2001 at a price of $126 per Mwh, and subsequently purchased 282 Gwh in these months at a total cost of $35.481 million.[92] In April 2001, pursuant to RFP IV, the Company purchased an additional 300 Mw per hour of on peak energy, paying $129 per Mwh for the 101Gwh purchased in July and $104 per Mwh for the 110 Gwh purchased in August, incurring a total cost of $24.485 million in these two months. The combined cost of the RFP III and IV energy purchases in the two months accordingly was $59.966 million (an average of $121.69 per Mwh), which when added to the $4.346 million cost of the 45 Gwh of other contractual energy purchases made in the two months, yielded the $64.312 million total cost of the 538 Gwh on which the RPA's recommended disallowance was based.

In addition to the third party purchases, the Company bought 158 Gwh from the PJM spot market in July at a cost of $13.013 million, paying an average price of $82.18 per Mwh, and 229 Gwh in August, for which it paid $34.740 million, or $151.51 per Mwh. For the two months combined, the average price was $123.19 per Mwh on purchases of 387 Gwh. The total cost of these energy-only purchases was $47.752 million. (P-8 at 9).

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92 Based on the Mwh and costs shown in Schedules 1(c) and 1(d) included with Schedule JAE-1 (Revised) attached to P-8 (the $129 price of the July and August RFP III purchases stated on page 8 of P-8 apparently should have been $126 per Mwh). The monthly breakdown of the energy purchases is also taken from Schedules 1(c) and 1(d).

In contesting the RPA's quantification of the disallowance, ACE argues that capping the cost of the third party purchases at the average cost of TBD generation and NUG power is inappropriate, in that "a significant portion of the cost of generation is a result of embedded capital invested long ago under different market conditions and costs of the NUG contracts are a result of agreements signed at different times and under different rules…In effect, Ms. Crane's approach is saying that the Company imprudently purchased energy at market prices and should have prudently purchased instead additional supplies of embedded cost generation. But, cost-based pricing had disappeared by 1999." (*Id*. at 12). The quantification was additionally asserted to be flawed because the proposed disallowance was determined by "mistakenly comparing base or intermediate load costs to peak period costs. Energy from the NUGs is produced virtually every day throughout the year and Atlantic's to-be-divested generation also produces energy year round during [sic] as intermediate or base load units. In contrast, the RFP III and RFP IV contracts were entered into for on-peak summer energy. Peak period summer costs are always going to be higher than average annual costs and a disallowance of the difference between the two is an indefensible position." (*Id*. at 13).

Considering first what might be characterized as the "embedded cost" versus "market price" issue, it is useful to break down the average cost of NUG power and the revenue requirement of TBD generation the RPA proposes to use as a cost cap into its component parts. As shown in Exhibit 5 attached, Atlantic's embedded supply sources in July and August of 2001 consisted of 459 Mw of NUG capacity,[93] B. L. England (447 Mw) and Keystone and Conemaugh (108 Mw combined). Of the total energy purchased from NUGs or generated in the two months, 56.3% was supplied by NUGs at a cost of $70.66 per Mwh, 30.8% was supplied by B. L. England at a cost (revenue requirement) of $65.75 per Mwh, and 12.9% by Keystone and Conemaugh at a cost (revenue requirement) of $21.29 per Mwh. An additional $10.3 million, the return on the Company's investment in its still-retained nuclear interests at 13.0% pre-tax, was also included in the cost of TBD generation in these months,[94] yielding an average cost of $72.00 per Mwh for the 1,114 Gwh generated or purchased from NUGs in the two months.

While the all-in cost of Keystone and Conemaugh energy is clearly economic, the cost of (i.e., the revenue allowed for) the other three components is more appropriately viewed as an allowance for stranded costs, directly so in the case of the above-market cost of NUG power and the revenue requirement of the nuclear units from which energy was no longer being received, and effectively so in the case of B. L. England, in that the market has determined that

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[93] The PPA contract capacity reported in AUD-2 at IX-1. The effective capacity is about 100 Mw higher (the excess capacity apparently available to the Company from the Chambers (Carney's Point) and Logan NUGs and Mobil), as shown in Schedule 1(b) included with JAE-1 (Revised) attached to P-8.

[94] Under the terms of the "virtual sale" executed with an affiliate of one of the purchasers of the Company's nuclear interests on October 7, 2000, the purchasers received an entitlement to the energy and capacity of the nuclear interests in return for assuming the units' operating and maintenance expenses (including fuel) and construction expenditures. (Exhibit S-1). The actual sale closed on October 18, 2001.

the plant has no value, as evidenced by the second failed auction noted above, yet the ratemaking accorded the plant during the Transition Period assured full recovery of all of its costs.[95] In the aggregate, the cost of these three components totaled $77.1 million in the two months at issue, or $79.54 per Mwh generated or purchased. Even after averaging in the cost of the economic Keystone and Conemaugh energy, the proposed cap exceeds 7 cents per kwh ($72.00 per Mwh, as noted above). Viewed this way, we believe capping the cost of the third party purchases at this level, as proposed by the RPA, to be reasonable; it is only by comparison to the July and August price spikes that such a cap could in any meaningful sense be considered "low." That is, absent the July and August price spikes, the use of Atlantic's average cost of NUG power (by definition, above market) and TBD generation, dominated as it is by the high cost of B. L. England generation, would be an unlikely choice for a benchmark, not because it is too low, as maintained by the Company, but because it is too *high*. We also note that the proposed cap is an all-in rate; that is, it includes capacity as well as energy costs, while the cost of the third party purchases at issue is energy only. If the capacity costs incurred pursuant to RFP IV (an average of $177.50 per Mw-day) were included in the comparison, an additional $7.7 million would be disallowed (700 Mw x 62 days x $177.50/Mw-day).

Moreover, it is important to note that the proposed cap was applied in only these two months. Had it been applied over the entire Transition Period, and to the cost of both the energy and the capacity purchased from third parties, the disallowance would have been $91.0 million. As shown in Schedule JAE-1 (Revised) attached to P-8, the cost of the Company's 3,956 Gwh of "Other Contracts" purchases was $315.5 million, or $79.76 per Mwh during the first three years of the Transition Period. After eliminating the pre-Transition Period PECO purchase (571 Gwh and $18.1 million, as indicated in Schedules 1(c), 1(d) and 1(e) attached to JAE-1), the cost of the remaining (the discretionary) 3,385 Gwh of "Other Contracts" purchases is $297.4 million, or $87.86 per Mwh. When added together, the "Generation" and "NUGs" categories shown in JAE-1 have a combined cost of $1.334 billion and combined energy generated and purchased of 19,117 Gwh, or $60.98 per Mwh. Applying the difference between $87.86 and $60.98 to the 3,385 Gwh of "Other Contracts" purchases, adjusted to eliminate the pre-Transition Period PECO purchase, would yield a disallowance of $91.0 million.

The reasonableness of the RPA's proposed cap is also supported by an estimate of the cost savings that might have been achieved in July and August 2001 if Atlantic had entered into at least one parting contract with the purchasers of its divested generating units. Using the nuclear units as an example, and assuming a bundled energy and capacity price of $35.58 per Mwh, the rate negotiated by JCP&L under its parting contract with the purchasers of Oyster

95 In its B. L. England Order *supra* (at 15), the Board likened the ratemaking treatment accorded B. L. England during the Transition Period to "a revenue requirement adjustment clause, which, subject only to a prudency review, provides for full and complete cost recovery of all costs incurred, on a timely basis, with interest on underrecovered balances, in contrast to base rate treatment, which requires periodic prospective Board approval of the appropriate level of such costs eligible for recovery based on a test year." Moreover, the investment and operating costs of the scrubber on Unit 1, which were not included in the test year of the Company's last base rate case, were included as part of MTC recoverable costs. (Exhibit S-2).

Creek for energy purchases made in the year 2001,[96] the reduction in Atlantic's energy and capacity costs in these two months would have been approximately $23 million[97] had the Company entered into a parting contract similar to JCP&L's Oyster Creek contract. Again, this is an estimate for just two months. Assuming the contract could have extended at least through July of 2002 in view of the 32-month term negotiated for the Oyster Creek parting contract, similar savings would have been achieved in that month. In July 2002, ACE purchased 246 Gwh of energy pursuant to RFP III and IV at a cost of $25.0 million, or an average of $101.43 per Mwh. Capacity was also purchased pursuant to RFP IV, 400 Mw at a cost of $150 per Mw-day and an additional 400 Mw at $125 per Mw-day, thereby incurring capacity costs of $3.4 million in July 2002,[98] as indicated in Schedules 1(c), 1(d) and 1(e) included with Schedule JAE-1 (Revised) attached to P-8. Under the assumptions just noted, a parting contract similar to that negotiated for Oyster Creek would have yielded estimated savings of about $9 million in this month, as well as additional savings over the other months of the contract term. Moreover, the still relatively high cost of the July 2002 purchases raises the question as to why the Company would want to have committed to such a high cost so far in advance, *i.e.*, at the time the RFP III and IV bids were awarded.

Turning to the Company's argument that it is inappropriate to compare the market price of on-peak summer energy to the cost of serving base and intermediate load year round, there is clearly merit to this argument. Yet if benchmarked on this basis, that is, if the cost of the Company's on-peak third party purchases were to be compared to the cost of on-peak energy available from a market-based alternative, *i.e.*, the PJM spot market, a far greater disallowance would result.[99] While it is true that the energy-only cost comparison between the RFP III and IV purchases and PJM is favorable in the months of July and August 2001 (if the 493 Gwh of third party purchases had been purchased in the PJM spot market, costs would have been increased slightly, by about $0.7 million[100]), over the three-year period ended July 31, 2002, the average

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96 Exhibit S-36, Docket No. ER0208057 *supra*. The term of the Oyster Creek parting contract was 32 months (from August 8, 2000 through March 31, 2003).

97 Energy cost savings = on peak energy of 239 Gwh (380 Mw at an approximate 90% capacity factor, 47% on peak) times the difference between the energy-only average price of the RFP III and IV purchases ($121.69 per Mwh) and the year 2001 bundled energy and capacity price under the Oyster Creek parting contract ($35.58 per Mwh) = $20.6 million, less $1.9 million from the sale of 270 Gwh of off-peak energy assumed re-sold at a loss of $7 per Mwh = $18.7 million, net. Capacity cost savings = 380 Mw x 62 days x $180 per Mw day paid for the second (the highest cost) increment of 400 Mw purchased under RFP IV = $4.2 million.

98 Similar to the increase in the BGS deferral that occurred in the months of July and August of 2001, these costs contributed to the $24 million increase in the BGS deferral that occurred in July 2002. (HACR-1, P-13).

99 In addition to the third party purchases, PJM was relied upon as a source of on-peak energy, since the Company's off-peak energy requirement was met by its nuclear units while retained, as well as NUG power and Keystone and Conemaugh throughout the Transition Period.

100 493 Gwh times ($123.19 per Mwh - $121.69 per Mwh).

cost of the on-peak third party energy and capacity purchases was over twice as high as the average cost of energy and capacity purchases from PJM.

As noted above, after eliminating the pre-Transition Period PECO purchase, the cost of the remaining 3,385 Gwh of "Other Contracts" purchases is $297.4 million, or $87.86 per Mwh. In making the on-peak comparison, however, a second adjustment is required to eliminate the "around the clock" purchase of 300 Mw per hour from Reliant Energy in the months of January through July 2002.[101] After eliminating this purchase (1,561 Gwh and $48.6 million, from Schedules 1(c) and 1(d) attached to JAE-1), the cost of the remaining 1,823 Gwh of third party purchases is $248.7 million, or $136.43 per Mwh, as compared to an average cost of $63.29 per Mwh for energy and capacity purchased from PJM, as shown in Schedule JAE-1. Applying this difference to the 1,823 Gwh of on-peak "Other Contracts" purchases yields an increased cost of $133.3 million relative to PJM. Clearly, the Advocate's recommended disallowance of $25.5 million is reasonable compared to the disallowance that could be justified based on this difference. Moreover, it represents approximately 5% of the cost of Atlantic's discretionary purchases and about 1.4% of the total cost of $1.853 billion incurred in obtaining the Company's BGS supply during the first three years of the Transition Period.

Finally, we observe that had the FSLO simply been extended on its original terms, the energy component would have been worth about $3.3 million to the Company and its ratepayers in August 2001.[102]

Giving weight to all of the above, we **HEREBY** **REJECT** the ALJ's finding on this issue, and **HEREBY** **ACCEPT** the RPA's proposed disallowance of $25.527 million of the Company's BGS deferred balance.

4. Excess Capacity Purchases

As summarized above, in her Direct Testimony as filed, RPA witness Crane recommended that ACE's deferred BGS balance be reduced by $3.728 million to reflect sales of excess capacity assertedly sold at a loss during the first three years of the Transition Period. (RA-2 at 19-20). As shown in Schedule ACC-5 attached to RA-2, this adjustment was quantified by taking, in each month in which both capacity purchases and sales took place, the difference between the average price paid for purchases in the month and the average price received from sales, and applying the difference to the megawatts of capacity sold. If the average sales price was less than the average purchase price, the difference, multiplied by the Mw sold, was to be disallowed, net of "profitable" sales in other months (months in which the average sale price exceeded the average purchase price). As filed, the quantification included the months of

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101 This purchase, the largest energy purchase made during the Transition Period, was not secured via an RFP, nor was it discussed in the Company's testimony, by any of the parties, or in the Audit Report.

102 260.4 Gwh times ($67.7 per Mwh - $55.0 per Mwh), where $67.7 per Mwh is the average PSE&G LMP for August 2001 from Appendix SIB-2 attached to Staff's Initial Brief.

February through August 2000, for which a net disallowance of $0.206 million was determined. However, Company witness Elliott subsequently testified that the capacity sales in these months should not have been included in the data supplied to Ms. Crane (*i.e.*, in Schedule 1(e) included in the Company's response to the RPA's discovery request RAR-MTC-13) since the capacity sold in these months was actually that of the Company's formerly owned, but now deregulated Deepwater plant and combustion turbines that had been transferred to its unregulated affiliate. (Tr. 148-152). During cross-examination witness Crane agreed that her recommended disallowance should be revised to eliminate these sales. (Tr. 612-613). The RPA accordingly proposed a reduced disallowance of $3.375 million in its Initial Brief.[103] (RIB at 5; 22-23).

Staff supports the RPA's recommended disallowance. While NJLEUC did not address either this or the RPA's proposed excess capacity adjustment associated with the TBD fossil units, it points out that two Board Orders had specifically cautioned the Company about securing too much capacity based on assumptions about the sale of the fossil units. (NJLEUCIB at 27). In rejecting the RPA's proposed disallowance, the ALJ cites the Company's arguments.

The Company argues that in lieu of identifying a single purchase or sale of capacity that was either imprudent or inconsistent with market conditions, witness Crane based her disallowance on an arbitrary and mechanistic method that compared the average price at which capacity was sold in a given month to the average price paid for capacity in that month without distinguishing between longer-term and shorter-term contracts. Thus if the Company purchased capacity under a 12-month contract at the prevailing market price, and for one month sold excess capacity, also at the prevailing market price, Ms. Crane's mechanical approach would disallow the cost of that portion of the 12-month contract price that is in excess of the sales price. (CIB at 20-21). The Company further asserts that the RPA's method converted transactions that were profitable relative to other transactions made with the same counterparty into "hundreds of thousands of dollars in disallowances." (*Id*. at 21). To illustrate its contention, ACE cites a purchase of 100 Mw from Exelon in February 2002[104] for which it paid $186,000 and a sale of 100 Mw to Exelon in that same month, the only sale in the month, for which it received $195,000.[105] The Company argues that under Ms. Crane's method, the apparent profit of

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103 The revised disallowance also reflected the correction of an error in the Schedule 1(e) data for May 2001.

104 The purchase and sale actually occurred in January 2002, and the amount received from the sale was $195,300, as shown in Schedule 1(e).

105 Capacity purchases and sales are priced in units of dollars per Mw-day (or sometimes in dollars per kw-month). Thus the amount paid for or received from a capacity purchase or sale reflects not just the amount of the capacity purchased or sold (the Mw), but for how long – a day, a week, a month or even a year or more, and is determined by multiplying the price per Mw-day times the number of days contracted for. While only the Mw purchased or sold and the related dollars paid or received are shown in Schedule 1(e) (and the unit costs in Schedule ACC-5 are expressed in dollars per Mw), calculations based on the per Mw unit costs are correct assuming all of the monthly cost data in Schedule 1(e) reflects purchases or sales made for the full number of days in the month. On the same assumption, the monthly cost data shown in Schedules 1(e) and ACC-5 can be converted to unit costs (prices per Mw-day) by

$9,000 on this sale becomes a disallowance of over $200,000, since the average price paid for all purchases in the month was considerably higher than the price obtained from Exelon. This and the other four transactions between Exelon and the Company that took place during the months of January through May 2002, all of which the Company contended were profitable, accordingly were converted into an aggregate disallowance of over $1 million under Ms. Crane's method. (*Id*. at 21-22).

While in the Company's view these transactions illustrate the flaw in the RPA's method, it argues that the proper test is not whether profits were made on individual transactions, but rather whether its actions were prudent, reasonable and consistent with market conditions during a period of turmoil in the capacity markets, when the Company also faced the additional challenge of matching unpredictable capacity needs and supply, as evidenced by the nearly 460 Mw of load that had been served by third party suppliers returning to BGS in just the seven month period from January through July 2001. (*Id*. at 22).

The Company further argues that it is improper to compare the revenue received from short-term capacity sales made in just one or two winter or spring months ("shoulder" months) to the cost of the 800 Mw purchased pursuant to RFP IV, which reflected the higher cost summer months averaged in as well, and which accounted for more than half of the total purchases on which the average purchase price used by Ms. Crane to determine profits or losses on capacity sales was based. In other words, the Company contends that it is improper to compare the price paid for capacity under a fixed long-term contract that includes the summer months to the price received from a short-term sale occurring in a shoulder month. (*Id*. at 23).

The asserted flaw in Ms. Crane's method was equally if not more apparent when it was applied in the month of May 2002, for which the proposed disallowance of $1.8 million comprised more than half the total recommended by the RPA. In addition to May being a shoulder month, the large May disallowance reflected the significant amount of capacity sold in that month (580 Mw), which the Company attributed to NRG's termination of the agreement to purchase the Company's fossil units. (*Id.*)

After carefully considering the arguments of the parties on this issue, the Board **FINDS** the Company's arguments to be flawed, and **FURTHER FINDS** the ALJ's reliance on those arguments to be misplaced. Accordingly, for the reasons discussed below, the Board **REJECTS** the ALJ's decision on this issue.

Preliminarily, the Board notes that absent an agreement to re-purchase the capacity sold to the Company by Exelon (for whatever reason and presumably under mutually acceptable conditions), the Company's attempt to match the Exelon sales one for one with an Exelon

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dividing the monthly cost by the product of the related Mw purchased or sold times the number of days in the month. Using the Company's Exelon transaction as an example, the price at which the 100 Mw was purchased was $60 per Mw-day ($186,000 divided by 100 Mw times 31 days), and the price at which the 100 Mw sale was made was $63 per Mw-day ($195,300 divided by 100 Mw times 31 days).

purchase of the same amount occurring in the same month appears to be facially simplistic, and not particularly meaningful for the purpose at hand. Absent such a "buyback" agreement (and the record does not disclose that one existed), for the Exelon transactions to make any sense, they must have been entered into at different times and under different circumstances. No rational seller would contract to sell capacity at a given price in a given month and simultaneously agree to purchase the same amount of capacity in that same month at a higher price. One plausible explanation for the Exelon transactions accordingly could be that well before January 2002, Exelon agreed to sell the Company 100 or more Mw in the months of January through July 2002,[106] only to subsequently discover that due to its own changed circumstances it needed capacity for some of these same months in a market that had by then moved higher, and purchased what it needed from the Company, which apparently had excess capacity available by then and offered it at a favorable price. Alternatively, the Company could have contracted to make the Exelon sales well before January 2002, only to subsequently find it needed more capacity than it originally thought it would need, and was able to buy it from Exelon at a favorable price in a market that had moved lower. Without knowing the dates the agreements to purchase and sell the various amounts of capacity were entered into, and other relevant facts, the Board can only speculate as to what might explain these transactions.

The Board further observes that there is only one circumstance in which a sale could unequivocally be linked to a given purchase, and that is when there is simply only one purchase. Obviously that is not the case here, as during the months of January through May 2002, when the Exelon sales were made, in addition to the 800 Mw purchased from the two winning RFP IV bidders, each of whom was awarded 400 Mw, the Company purchased an average of 670 Mw from four to five other sellers, including Exelon. Thus during these months, the Company was purchasing varying amounts of capacity at varying prices from as many as seven different sellers. To say to which of these purchases the Exelon sales should be matched for purposes of imputing profits or losses is therefore an allocation issue, on which opinions may differ. One could argue that the most recent purchase is to blame for the excess capacity, analogous to the LIFO ("last in, first out") method of charging out inventory. Alternatively, it could be argued that the most expensive purchases (the two RFP IV purchases) should be used, because buying too much of that capacity had the greatest impact on costs. Ms. Crane's method, using the average of all purchases, is, to cite the inventory example once again, analogous to charging out inventory at average cost, and, in the Board's view, strikes a reasonable balance, proposing as it does in months when both purchases and sales of capacity were made to disallow purchases equal in amount to the sales and priced at the average cost of the purchases, net of the amount received from the sales. Moreover, her method was symmetrically applied, resulting as it did in a gain of $0.374 million on the sale of 150 Mw in June 2000, before it was discovered that this was a sale of Deepwater capacity and/or the capacity of the transferred CTs, and thus was removed from the utility.

Turning to the Company's argument that it is improper to compare the cost of a fixed price, long-term purchase that includes the summer months (*i.e.*, the 800 Mw purchased under RFP IV), to

106 As shown in Schedule 1(e), ACE purchased 100 Mw from Exelon in January and February, 200 Mw in March, 250 Mw in April and May, 100 Mw in June, and 200 Mw in July of 2002.

the amount received from a short-term sale in one or more shoulder months, while the Board is not convinced that capacity costs exhibit the same degree of seasonality as do energy costs (the installed capacity of suppliers in the region appears to be a more significant determinant of capacity costs than does weather, for example), the Board agrees that all other things remaining equal, the average 12-month cost of capacity would be expected to exceed the cost of capacity in the shoulder months. By the same token, the 12-month cost should be less than the cost in the peak summer months (July and August, typically). Based on the Schedule 1(e) data supplied by the Company, this was not the case for the RFP IV purchases, suggesting that the high price of these capacity purchases reflected more than just averaging in the peak summer months.

RFP IV was issued on March 21, 2001, and is discussed in Chapter VIII of the Audit Report (AUD-2 at VIII-10 to 11, and VIII-33 to 35), as well as in the Board's Order approving, *nunc pro tunc,* the issuance of this RFP (the "April 27, 2001 Order").[107] In RFP IV, the Company sought 400 Mw of capacity for the 16-month period from June 2001 through September 2002,[108] as well as 300 Mw per hour of on-peak energy (energy to be delivered in the hours from 8:00 a.m. through 11:00 p. m. on weekdays, excluding holidays) and 300 Mw per hour of "super-peak" energy (energy to be delivered in the hours from 12 noon through 7:00 p.m. on weekdays excluding holidays) to be supplied during the months of July and August 2001 and July 2002. Final bids were due on April 27, 2001, with an award to be made that same day, and supply (the capacity purchases) to begin on June 1, 2001.

Although only 400 Mw of capacity was sought, the Company estimated that its need for capacity could be as high as 1,000 to 1,200 Mw. However, to avoid potentially increasing the market price by seeking an amount that high, on the advice of its consultant, Lexecon, the Company limited the RFP to 400 Mw on the basis that if the bids it received were favorable, nothing would preclude it from purchasing more. Accordingly, the Company awarded 400 Mw to each of two

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107 In Docket No. EM01030162, *I/M/O the Petition of Atlantic City Electric Company for Approval of a Request for Proposals, Authorization of a Competitive Procurement and to Enter into a Contract for Basic Generation Supply*, Order dated April 27, 2001.

108 PJM had apparently extended the period during which it would impose capacity deficiency penalties to encompass the months of June through September. (P-8 at 15). The April 27, 2001 Order noted (at 3) that "the Company seeks a term for capacity deliveries terminating on September 30, 2002, two months beyond its July 31, 2002 energy supply solicitation. The stated reason for the extended capacity solicitation is a proposed PJM rule change, which if adopted by FERC, would modify the capacity deficiency penalties for any deficiencies occurring during the June through September summer interval within any year where Load Service [sic] Entities ("LSEs") within PJM, which do not have enough capacity to meet their capacity obligation under the PJM Reliability Assurance Agreement ("RAA"), are charged a capacity deficiency penalty. The Company's extended RFP solicitation for capacity is designed to guard against the imposition of the deficiency charges during the July-August 2002 period should ACE be in the position of the supplier of last resort for BGS service." Still, the Company did not explain in its filing why it needed to contract for capacity after August 1, 2002, when capacity costs would be included in the bundled price of power obtained via the statewide BGS auction.

winning bidders, citing returning customers who had chosen third party suppliers as having contributed to the decision to accept the additional bid. (*Id.* at VIII-33 to VIII-34).

Of the two winning bids, the lowest was priced at $175 per Mw-day for capacity purchased from June 1, 2001 through May 31, 2002, and $125 per Mw-day for purchases from June 1, 2002 through September 30, 2002. The average price over the 16-month period was $162.50 per Mw-day. The second bid was priced at $180 and $150 per Mw-day over the same periods, for an average price of $172.50 per Mw-day over the 16-month period. On a combined basis, the average price of the 800 total Mw purchased was $177.50 per Mw-day from June 1, 2001 through May 31, 2002, and $137.50 per Mw-day in June and July 2002,[109] as shown in Exhibit 4 attached.

Of the prices paid for the contractual capacity purchases shown in Schedule 1(e), the $180 per Mw-day paid for the second block of 400 Mw purchased pursuant to RFP IV was exceeded during the Transition Period only by the $190 per Mw-day paid Enron for the purchase of 11 Mw in July 2001. The price of the first 400 Mw, at $175 per Mw-day, was not far behind. Moreover, the price of the combined purchases, at $177.50, exceeded the PJM capacity deficiency rate for a full year.[110] As shown in Exhibit 4, for the 14-month period from June 1, 2001, when the RFP IV purchases began, through July 31, 2002, the average cost of the RFP IV purchases, at $171.77 per Mw-day, also exceeded the average cost of all other contractual purchases of capacity during this period by $63.05, or by approximately 60%.[111] The Exhibit also shows that if priced at the average cost of the other purchases, the cost of the RFP IV purchases would have been approximately $20 million lower. Moreover, the RFP IV cost was well above the

[109] The last month for which data was provided in Schedule 1(e), which was not updated. Thus, the record does not disclose whether sales of excess capacity occurred in the months of August and September 2002, in which the 800 Mw contracted for pursuant to RFP IV continued to be purchased at an average cost of $137.50 per Mw-day, thereby incurring a total cost of $6.710 million in these two months.

[110] $176.30 per Mw-day. (P-8 at 15). According to the Company, PJM changed its rules early in 2001 to impose 122 days worth of capacity deficiency penalties if a Load Serving Entity was deficient for a single day in the June- September period. (*Id.* at 14).

[111] Based on the data shown in Schedule 1(e), the total cost of Atlantic's contractual capacity purchases was $103.1 million, or $130.11 per Mw-day during the first three years of the Transition Period. Excluding the PECO purchase, which was entered into prior to the Transition Period and had energy associated with it and thus was not comparable to the other capacity purchases, the cost was $98.3 million, or $130.37 per Mw-day. The cost of all contractual purchases other than the RFP IV purchases was $39.8 million, or $96.22 per Mw-day. The cost of the RFP IV purchases was $58.5 million, or $171.77 per Mw-day. These amounts do not include the adjustment of approximately $12.9 million added to "Other Contracts" costs in the second (January 24, 2003) revision to Schedule JAE-1 included in P-8, as compared to the first (November 17, 2002) revision included in RA-2. A more comprehensive summary of the Company's capacity purchases during the first three years of the Transition Period is included in the Audit Report as Exhibit VIII-13. However, starting in the month of November 2001, there apparently is a classification difference between the contract capacity purchases shown in that Exhibit and Schedule 1(e).

average cost of purchases secured for the summer month of July 2002 ($97.74 per Mw-day), and for the summer months of July and August of 2000 as well ($85.75 per Mw-day).[112]

Thus, more relevant in our view than the debate over comparing a 12-month average to individual months that the data suggests could not have been included in that average (which if anything appears to have reflected just the peak summer months with little or no allowance for the lower cost shoulder months), are questions raised by the high cost of the RFP IV purchases themselves, in particular, why they were entered into for a term as long as 16 months, given this high cost and the apparent expectation that capacity prices would go down, as evidenced by the reduction in the price of the capacity contracted for after the first 12 months (from $175 per Mw-day to $125 per Mw-day effective June 1, 2002 for the first 400 Mw purchased, and from $180 per Mw-day to $150 per Mw day for the second 400 Mw purchased).[113] While the RFP apparently allowed for flexibility in the amount of capacity (Mw) that could be purchased, it appears that there was no similar flexibility allowed or judgment shown when it came to the term (how long) the capacity could be purchased for. Nor is it clear why a rate higher than PJM's capacity deficiency rate would be committed to in months other than June through September, the period for which deficiency penalties were imposed by PJM.

Referring again to the Audit Report, the Auditors noted that the two bids chosen were below the Company's benchmark estimate of $173.80 per Mw-day, based on the broker market. (AUD-2 at VIII-34). Exhibit 4 also shows that the combined cost of the 800 Mw of purchases was not that much higher (about 10%) than the cost of the other capacity purchases entered into for the June – December 2001 time period. As shown in Exhibit VIII-13 of the Audit Report, the cost of PJM capacity purchases (*i.e.*, non-contractual spot purchases) had gone up significantly in April 2001, and spiked even higher in July. The Company accordingly contends that its actions in issuing and accepting bids in response to RFP IV were prudent, in that it chose the lowest bids, and the bids were based on market conditions that existed at the time. The Board notes there was yet another option, rejecting the bids and relying on the PJM capacity markets on the basis that the Company was not likely to do any worse, given bids as high as these. As discussed above in connection with the RPA's recommended disallowance of what it deemed to be the excessive cost of the July and August 2001 third party purchases, the RPA and the other parties contend that, had the Company made better choices throughout the Transition Period, if it had managed its BGS procurement more effectively, *i.e.*, if it had a parting contract in place, it could well have avoided the prospect of being confronted with a decision to accept bids for 800 Mw of capacity priced between $162.50 and $200 per MW-day. We agree, and accordingly find the

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112 Purchase data from Schedule 1(e), which typically reflects contracts of several months duration, was used in making the comparison in the absence of contractual sales data for the peak summer months.

113 While the 200 Mw obtained under RFP III was purchased for a term of 19 months (from January 2001 through July 2002), the pricing for 10 months of the term was at the relatively favorable rates of $45 and $57 per Mw-day. The Auditors accordingly found that the Company should have purchased the full 400 Mw offered in response to this RFP.

arguments advanced in support of the RPA's recommended energy cost disallowance, as discussed above, to be equally applicable here.

With respect to the Company's assertion that the magnitude of the recommended May 2002 disallowance in part reflects the termination of NRG's agreement to purchase the fossil units, and the implication that the Company should not be penalized for that, while it is true that the 580 Mw of capacity sold in that month approximates the capacity of the fossil units (555 Mw), it does not appear from the data in Exhibit 4 that the Company's May capacity purchases had increased by that amount in anticipation of a successful sale. In the months from June 2001 through February 2002, with the fossil units retained, an average of approximately 540 MW was purchased, other than the 800 Mw purchased pursuant to RFP IV. In March, April and May, capacity purchases increased, apparently due to forward purchases made in response to the Board's approval of the NRG sale in January. In May, 737 Mw was purchased, but this was only about 200 Mw more than had been purchased while the fossil units were retained. In June, non-RFP IV purchases dropped to 558 Mw, suggesting that by then the impact of the failed NRG sale on the Company's contractual capacity purchases had largely, if not completely been eliminated. Thus the impact of the failed NRG sale appears to have been substantially less than the Company suggests. Moreover, an analysis of the May capacity sales raises a question as to whether the Company got the best price it could have for these sales, in that it received $39.43 per Mw-day for the 175 Mw sold to Exelon, but only $10 per Mw-day for the 80 Mw sold to Morgan Stanley, and even less, $8 per Mw-day, for the 325 Mw sold to Williams, as shown in Schedule 1(e).

Finally, in view of the fact that the FSLO executed in connection with the sale of the Company's nuclear units provided for the purchase of 372 Mw of capacity as well as energy during the peak summer months of June, July and August 2000, if the Company had negotiated an extension in the FSLO to cover the summer months of 2001 when it entered into the virtual sale of its nuclear units, those months and that amount of capacity could have been excluded from one of the 400 Mw blocks it sought in RFP IV. Under a renegotiated FSLO, capacity almost certainly could have been obtained at a better price, in that it would have been negotiated prior to the run-up in capacity prices that began in early 2001. Had the FSLO been extended at the original capacity price of $60 per Mw–day, the savings, as compared to paying $180 per Mw-day for the 372 Mw, would have been $4.1 million.

To be clear, in reviewing the results of RFP IV it is not the Board's intent to go beyond the capacity cost disallowance recommended in the record. We do believe, however, that the reasonableness of this disallowance, as well as the energy cost disallowance discussed above, should be judged in the broader context of the Company's performance during the Transition Period as a whole. We also recognize that the issuance and outcome of this RFP was approved by the April 27, 2001 Order. At the same time, that Order made it abundantly clear (at 3 and again at 4) that the Company would be required "to demonstrate, in an appropriate future proceeding, the reasonableness and prudence of its actions for obtaining capacity and energy including its decision to accept or not accept bids it may receive as a result of the instant RFP [RFP IV]."

For these reasons, the Board is persuaded by the arguments of the RPA and Staff, and **HEREBY REJECTS** the ALJ's findings on the issue. Accordingly, the RPA's recommended BGS disallowance of $3.375 million is **HEREBY ACCEPTED.**

2. BGS Administrative Costs

In arguing that the Company failed to demonstrate the reasonableness of the $3.528 million of BGS administrative costs it claimed in its Petition, and thus that they should be disallowed, the RPA additionally contends that costs of this type should in any event not be included in the BGS deferral, since they are normally recovered by base rates. In response, the Company contends that these costs were appropriately incurred in administering its BGS supply, and could not have been included in its current base rates, since they were last set in 1991. Moreover, all generation-related costs were assertedy eliminated from its base rates when they were unbundled in the Board's restructuring proceedings. In lieu of the disallowance proposed by the RPA, Staff recommends that these costs undergo further review in the Company's pending base rate proceeding.

While rejecting the RPA's proposed disallowance, the ALJ nonetheless observes that $1.398 million of "merchant support costs" were included in the Company's claimed BGS administrative costs, and that the Auditors had questioned the inclusion of these costs in the deferred BGS balance, finding that such inclusion had not been authorized by a Board Order. (I.D. at 75, referencing the Auditors' finding at III-5 of AUD-2). Although not quantified, in response to cross-examination at the February 27, 2003 hearing, the Auditors also agreed that the costs incurred in preparing the flawed RFPs I and II should be borne by the Company. (Tr. at 958).

For these reasons as well as the reasons advanced by the RPA and Staff, the Board is persuaded that the Company's BGS administrative costs should undergo further review in its pending base rate case, and **HEREBY MODIFIES** the Initial Decision accordingly. The merchant support costs questioned by the Auditors and the costs associated with RFPs I and II shall also be added to the list of carry over issues from this proceeding that are to be addressed in Phase II of the base rate case.

3. LEAC Interest

As indicated above, the RPA argues that the methodology used with the Company's LEAC in effect prior to August 1, 1999 called for annual true-ups and interest determinations over such annual periods. Thus, the RPA proposed an increase in the July 31, 1999 overrecovered balance of the Company's LEAC (the beginning balance of the BGS deferral) of $1.993 million to reflect two such annual determinations within the 26-month period spanned by the LEAC before it was discontinued on August 1, 1999. While the Company agrees that its LEAC revisions were designed for 12-month periods, it observes that in many cases its LEAC rates remained in effect for periods greater or less than that, and in such cases the interest determination encompassed the period during which the LEAC was in effect. (P-3 at 3-4). Moreover, N.J.A.C. 14:3-13, which states how interest on LEAC over and underrecoveries was to be determined, permitted clause charges to be in effect for periods other than 12 months if specified by the Board in a rate proceeding, and for interest to be calculated over the "clause period," the period in which the clause charge was in effect. NJLEUC took no position on this issue. While Staff took no position in its Briefs, it agreed with the Company in its Exceptions to the Initial Decision. The ALJ also agreed with the Company, and so do we. Accordingly, we **HEREBY ADOPT** the finding of the ALJ on this issue, and **HEREBY DENY** the RPA's proposed reduction of $1.993 million in ACE's deferred BGS balance.

In considering this issue it appears that a minor clarification of the record is appropriate. The Board notes that both the ALJ and the Company have asserted that the RPA and Staff proposed net of tax treatment with respect to the LEAC interest issue (I.D. at 17; Company Reply Exceptions at 5), when in fact the proposed treatment applies only to interest accruals on post August 1, 1999 deferrals and deferral recovery, as indicated *supra,* and discussed more fully below.

B. MTC DEFERRED BALANCE

1. Above-Market Costs of TBD Fossil Units

(a) Excess Capacity Disallowance

As discussed above, the RPA recommends limiting the above-market cost of the generation from ACE's retained fossil units recoverable by the MTC to $1.084 million per month, effective August 1, 2002, the month in which the units assertedly became excess capacity as a result of ACE having assumed they would be divested by then in contracting for its BGS supply for the final year of the Transition Period. The $1.084 million is the return on the units' stranded costs calculated by the Company at the 13.0% pre-tax rate in the months following March 2003, the month in which the fossil units were again assumed to have been divested, this time pursuant to the second auction conducted in the summer and fall of 2002. By taking the difference between the above-market component of the revenue requirement of the units and the return on the units' stranded costs in the months of August 2002 through March 2003, the RPA determined a proposed disallowance of deferred MTC costs of $29.569 million, with no offsetting credit given for the revenue received from sales of the units' capacity and energy during this period.[114] Effective August 1, 2003, the RPA further proposed reducing the 13.0% pre-tax return to the cost of debt found by the BPU and the ALJ to be reasonable. (RIB at 29; RA-2 at 39-40).

ACE does not dispute the fact that the fossil capacity became excess when it began obtaining auction power on August 1, 2002, but asserts that the excess was due to NRG having

[114] As her reason for not reflecting such a credit, RPA witness Crane cited the lack of timely discovery responses from the Company. However, in its Initial Brief the Company notes that credit for energy and capacity sales had effectively been reflected in the MTC balance by virtue of continuing to include the "at market" component of the costs of the fossil units in BGS recoverable costs (the generation of the fossil units priced at the BGS price). (CIB at 33, footnote 8).

terminated its agreement to purchase the units after the Company had already committed to the BGS supply needed for the final year of the Transition Period. The Company also asserts that all of the revenue received from the sale of the units' energy and capacity was credited to the MTC deferred balance, and that ratepayers benefited from the retention of the units, in that their operating costs were assertedly lower than, or in line with those of alternative sources of supply. (P-8 at 20-23). The Company additionally contends that the RPA's proposed reduction in the units' revenue requirement from approximately $6 million per month to $1.084 million per month far exceeds the revenue attributable to the 13% pre-tax return, and thus would deny the Company recovery of its operating costs as well. (CIB at 33-34).

While NJLEUC did not directly address the RPA's proposed disallowance, it asserts that "notwithstanding the specific warnings set forth in two Board Orders that the Company should avoid purchasing excess capacity based on its assumptions about the proposed fossil sale, Atlantic did, in fact, find itself with surplus capacity when the sale was cancelled." (NJLEUCIB at 27). While contending that the Company's deferred MTC balance is too high, NJLEUC attributes the assertedly excessive balance to the inclusion in the MTC of lost revenues (the difference between the revenue requirement of the TBD units and the revenue received from the shopping credit), rather than true stranded costs, without regard to whether the lost revenue is temporary or permanent. NJLEUC additionally maintains that the 13.0% pre-tax return is excessive, and should be reduced to a debt rate. (*Id*. at 29-30, 34).

While fully supporting the Auditors' recommended review of B. L. England's operation and maintenance expenses, Staff does not support the RPA's recommended disallowance for the reasons stated by the Company.[115] With respect to the proposed reduction in the 13.0% pre-tax return, Staff noted that this issue was before the Board in another proceeding, and thus did not take a position on the issue here.

In rejecting the RPA's recommended excess capacity disallowance, the ALJ found that the excess capacity was largely due to the failed NRG sale, and not to any unreasonableness on the Company's part. The ALJ also faulted the RPA for failing to calculate the revenue received from sales of the energy and capacity of the retained units, which she noted are credited to ratepayers who arguably benefited from the retention of the units, since the operating costs of the units are assertedly lower or in line with the cost of alternative sources of supply. As to the 13.0% pre-tax return issue, the ALJ found that the return should include an equity as well as a debt component, and should not be adjusted in this proceeding but in the Company's pending base rate case, and set at the rate determined in that proceeding. (I.D. at 86-90).

In view of the Board's approval of the NRG sale at its January 31, 2002 public meeting, and the necessity for the Company to have contracted for its BGS supply for the final year of the Transition Period by February 15, 2002, we agree with the ALJ and Staff that it was reasonable at that time for the Company to have assumed that the fossil units would be divested by the time

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[115] As noted *supra*, Staff does not, however, agree with the Company that the retention of B. L. England benefited ratepayers.

its year four auction power began flowing on August 1, 2002. We also note that following the termination of the fossil sale by NRG on April 1, 2002, the Company acted expeditiously to re-market the units, initiating a second auction process in May 2002, and advising the Board and the RPA of the auction by letter dated May 23, 2002. For these reasons, the Board **HEREBY AFFIRMS** the finding of the Initial Decision on the excess fossil capacity issue, and **HEREBY REJECTS** the $29.569 million MTC disallowance proposed by the RPA. Additionally, the Board **REJECTS** NJLEUC's contention that the MTC deferred balance improperly includes lost revenues which assertedly could be offset by BGS revenue received after the deferral period. As the Company points out in its Reply Exceptions (at 21), under the auction, the revenues received for post-transition BGS supply are to be remitted to the suppliers of that power, not retained by the Company.

(b) Reduction in 13.0% Pre-Tax Return

With respect to the RPA's and NJLEUC's proposed reduction in the 13.0% pre-tax return to a debt rate, this issue, as it applied to B. L. England, as well as the continuation of the ratemaking treatment accorded B. L. England by the Final Restructuring Order, was subsequently considered by the Board in a separate proceeding, as noted above by Staff.

(c) Review of B. L. England's O&M Costs

In view of B. L. England's cost and performance trends and the impact of its forced outages and reserve shutdowns on its use for congestion management in the area it serves, the Auditors recommended that a detailed review of ACE's operation and maintenance of the plant be performed. Staff supported this recommendation, while the ALJ did not. (I.D. at 90). Based upon its review of the record, the Board disagrees with the ALJ on this issue, and concurs with Staff and the Auditors that a more detailed review of the Company's operation and management of B. L. England is warranted. In our September 25, 2003 Order in Docket Nos. EO03020091 *et al.*, the Board determined that B. L. England's operation and maintenance expenses, which in that proceeding were estimated to exceed the revenue received from sales of the plant's capacity and energy by about $20 million annually, should undergo further regulatory review in the Company's pending base rate case. The issue as to whether and how such costs should be shared between ratepayers and shareholders is also to be reviewed in the pending base rate case, as set forth more fully in the Board's Orders issued in Docket Nos. ER02080510, *et al.* dated December 12, 2003 and January 26, 2004.[116]

[116] *I/M/O the Petition of Atlantic City Electric Company d/b/a Conectiv Power Delivery for Approval of Amendments to its Tariff to Provide for an Increase in Rates for Electric Service,* Docket No. ER02080510 (deferred balances proceeding); *I/M/O the Petition of Atlantic City Electric Company for an Administrative Determination of the Value of Certain Fossil Generation Assets,* Docket No. EO03020091 (B. L. England proceeding); *I/M/O the Petition of Atlantic City Electric Company, Conectiv Communications, Inc., and New RC, Inc., for Approval Under N.J.S.A. 48:2-51.1 and N.J.S.A. 48:3-10 of a Change in Ownership and Control,* Docket No. EM01050308 (Service Agreement proceeding).

2. Cash Working Capital, TBD Units

As summarized above, the RPA recommends that the cash working capital and related return included in ACE's determination of the revenue requirement of the TBD units be disallowed. At issue are the lead/lag days assumed by the Company, which the RPA argues are out of date and were never specifically approved by the Board, as well as the inclusion of depreciation expense and the omission of debt interest in the CWC calculation and the 13% pre-tax rate used to calculate the return, which the RPA maintains is inappropriate, since the Company was compensated by accrued interest on the deferred balance during the Transition Period. NJLEUC contends that the revenue lag assumed by the Company was too long; that its CWC calculation did not reflect the lag in the payment of debt interest; and that it improperly included such non-cash items as depreciation and amortization in the calculation. ACE asserts that it was appropriate to use the last available study to avoid the cost and complexity of performing a new CWC study, and that the inclusion of depreciation expense in the calculation is necessary to properly compensate investors for the reduction in rate base attributable to the depreciation reserve. By not reflecting any return, including the equity component in its calculation, the Company argues that it took a conservative approach.

Staff agreed with the Company, as did the ALJ in rejecting the RPA's recommended $3.793 million working capital-related reduction in ACE's deferred MTC balance. Based upon our review of the record, the Board **HEREBY ACCEPTS** the ALJ's finding on this issue, and finds that the 13% pre-tax return was applied in accordance with the Final Restructuring Order. To the extent the return was not recovered during the Transition Period, it was eligible to accrue interest, just like any other component of the revenue requirement of the TBD units. Moreover, as Staff notes, in addition to the working capital adjustment, ACE properly and consistently reflected a consolidated tax adjustment, which reduces the revenue requirement, in calculating the revenue requirement of the TBD units.

3. Restructuring/Third Party Billing Costs

The parties raise a number of issues with respect to the Company's claimed restructuring costs, chief among them the contention that ACE did not meet its statutory burden of proof required for the recovery of these costs. Moreover, while authorized for the recovery of the capital component of restructuring costs by the Final Restructuring Order, the Company proposes to apply the 13% pre-tax return to the unamortized balance of deferred restructuring-related operating costs as well, which both the RPA and Staff argue is improper. Staff additionally argues that the capital component should be amortized net of tax. The RPA and Staff also contend that the ongoing component of restructuring-related operating costs should be considered a base rate expense, and set at an appropriate level in the Company's pending base rate case. Staff, the RPA and NJLEUC all express concern that some portion of the claimed costs may not be incremental, *i.e.*, that they may be, at least in part, recovered by the Company's current base rates. NJLEUC additionally recommends that half of the $9 million of capital expenditures made on the Company's Customer Care System be disallowed in view of the system's asserted shortcomings, including its asserted inability to issue fully automated bills to ACE's largest customers.

With respect to the costs claimed by the Company in implementing third party consolidated billing, the RPA contends that, in addition to not having been adequately supported by the Company, the treatment proposed in ACE's filing does not conform to the Board's Order in the Customer Accounts Services proceeding (Docket No. EX99090676).[117] Accordingly the RPA recommends that $4.052 million of such costs be disallowed. (RA-2 at 41-42; RIB at 5, 31-32).

Although Staff agrees with several of the RPA's contentions, it does not propose that the costs at issue be disallowed, but recommends that they undergo additional regulatory review in the Company's pending base rate case.

The Company defends its claimed restructuring costs by asserting that they were both necessary and prudently incurred in carrying out the mandates of EDECA and the Board's Orders issued in implementation thereof. (P-5 at 5-8). The ALJ agrees, and rejected both the RPA's recommended disallowance of $15.307 million of restructuring costs (I.D. at 95) and its proposed disallowance of $4.052 million of consolidated third party billing costs (*Id*. at 98-99) from the Company's deferred MTC balance.

The Board agrees with Staff that the record on the costs at issue has not been sufficiently developed, particularly with respect to the ratemaking treatment to be accorded these costs, and accordingly, we defer our decision on both the recoverability and ratemaking treatment pending further review of these issues in the Company's pending base rate case.

C. <u>NNC DEFERRED BALANCE</u>

1. <u>Heat Rate Dispute, Logan NUG</u>

The Company included in its deferred NNC balance approximately $2.5 million of legal expenses incurred in an ongoing dispute with Logan over the calculation of the facility's heat rate, arguing that whether received directly, as in the case of a refund of past alleged overcharges, or indirectly in the form of lower payments over the remaining life of the PPA, all benefits from the litigation will be credited to the NNC balance via the annual revisions and true-ups of its NNC charges. If successful, the Company estimates that the litigation could yield a refund to ratepayers of $3 million or more attributable to past alleged project overcharges, and an additional benefit of $1 million annually over the 22-year remaining life of the Logan PPA. The RPA proposes excluding the legal costs incurred to date from the NNC balance pending the ultimate resolution of the dispute. Staff and Cogentrix support the RPA's proposal.

As indicated in the Summary Order in this Docket (at 4), the Board has determined to defer its decision on this issue pending further review in the Company's pending base rate case. As further indicated in the Summary Order, following the Board's public meeting on July 21, 2003 at which it rendered its oral decision in this proceeding, the Company reminded Staff that $4.6

[117] *I/M/O the Electric Discount and Energy Competition Act of 1999 – Customer Account Services*, Docket No. EX99090676, Order dated December 22, 2000, Atlantic City Electric Company, Attachment E.

million received from Logan in partial settlement of the dispute was credited to the NNC balance in May 2003. In a footnote on page 4, the Summary Order inadvertently noted that "$2.5 million of related costs should now appropriately be debited to the balance as well." Upon review, the Board has concluded that the footnote needs to be clarified. The Board notes that legal expenses have traditionally been recovered through base rates, as opposed to clause treatment with true-ups, at some representative level established in a base rate proceeding. On the other hand, to the extent that the expenses incurred in pursuing the Logan dispute are non-recurring and incremental to the ongoing level reflected in the Company's base rates, NNC treatment, as proposed by the Company, may be warranted, especially in view of the fact that the $4.6 million settlement payment has been credited to the NNC. Accordingly, in its Order dated December 12, 2003 in Docket Nos. ER02080510 *et al* discussed *supra*, the Board indicated (at 3, footnote 6) that it would reconsider the treatment of the legal and other costs incurred by the Company in the Logan dispute in Phase II of the Company's pending base rate case. Pending the conclusion of that proceeding, we believe it appropriate to continue, on an interim basis, to reflect both the Logan costs incurred and the settlement payment received in the NNC balance.

2. Pedricktown Buyout Interest

The Auditors have found that the Company's share of a tax refund received by the Conectiv Group in connection with the buyout of the Pedricktown NUG PPA ($61.4 million of the total refund of $64 million) should have been recorded one month sooner than it actually was, and that if it had been so recorded, the buyout interest included in the NNC would have been reduced by $0.459 million. (AUD-2 at I-5). This adjustment was supported by the RPA and Staff, and accepted by the ALJ. The Board accordingly **HEREBY DIRECTS** the Company to reduce its deferred NNC balance by this amount.

3. Reporting Requirements

While rejecting Staff's and the RPA's proposed NUG reporting requirements on the basis that "[t]he ramifications and extent of reporting, including costs thereof, pertinent to Staff's recommendation, especially, are not addressed in the record," the ALJ noted that there is nothing to prevent the Board from implementing such reporting requirements on its own initiative. (I.D. at 103). In view of the magnitude of the Company's above-market NUG costs, which even after the buyout and buydown of the PPAs with the Pedricktown and DRMI NUGs have been estimated to be as high as $1.2 billion over the life of the remaining PPAs,[118] it is essential that the Company remain diligent in its efforts to further mitigate these costs. Moreover, in view of the on again, off again nature of the discussions with NEG, the part-owners of the Carney's Point and Logan NUGs, as recounted in the Phase I Audit Report and noted *supra*, it is incumbent upon the Company to keep the Board apprised of the status of these discussions on a regular and ongoing basis. While the RPA has proposed the filing of annual status reports when the Company's NNC charges are changed, consistent with the quarterly filings now being made by JCP&L, as well as our directive to RECO to begin filing such reports

[118] As indicated in the Audit Report at IX-2.

quarterly,[119] we **HEREBY REJECT** the ALJ's recommendation on this issue and **HEREBY DIRECT** the Company to begin filing, on a calendar-quarter basis, quarterly reports with the Board that provide the status of the Company's efforts to buy out or re-negotiate the terms of its PPAs with the owners of its remaining NUGs, with the first such report due within 90 days of the date of this Order. These status reports shall be in addition to, and consolidated with, the monthly reports the Company is also directed to file, as discussed below.

In addition to using its best efforts to mitigate its NUG contract costs, the Company must also insure that its NUG generation and capacity is utilized in the most cost-effective way for the benefit of its ratepayers. Even with the PPA with the Pedricktown NUG bought out, the contract capacity of ACE's remaining NUG PPAs remains substantial,[120] thus whether the full value of the NUG output and capacity can best be realized by re-selling the NUG output in the PJM markets, or by devoting it to the supply of BGS service, remains an important concern of the Board. In responding to that concern, Staff recommended that Atlantic be directed to file the monthly NUG and pricing data discussed *supra*. The Board agreed, and so directed the Company in our July 31, 2003 Summary Order issued in this Docket.

As issued, the Summary Order directed the Company "to file monthly reports with the Board that show, for its share of each NUG project, the energy and capacity purchased (MWH and MW), the amount paid for energy and capacity, the disposition of the energy and capacity (i.e., whether it was resold in the wholesale power market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rates, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction." Upon review, we **HEREBY CLARIFY** this directive to read: "We **HEREBY DIRECT** the Company to file monthly reports with the Board that show, for each NUG with which the Company has a PPA, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (*i.e.*, whether resold in the wholesale power market, or if not, what other disposition of the energy and capacity was made), the amount received from the sale of the energy and capacity, as well as the value of the energy and capacity if the energy were priced at the PJM Locational Marginal Price (LMP) for the Zone in which the Company operates and the capacity were priced at the average rate at which PJM capacity sales were transacted during the month. The value of the energy and capacity if priced at the energy and capacity components of the rate payable for BGS supply obtained pursuant to the statewide auction, or if not known precisely, a reasonable estimate thereof, shall also be provided." The Board notes that the first such report was due 30 days from the date of the Summary Order. In view of the clarified reporting requirement ordered herein, we **HEREBY DIRECT** the Company to revise and re-file all previously-filed reports to conform them to the above directive.

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119 *I/M/O the Verified Petition of Rockland Electric Company for the Recovery of its Deferred Balances and the Establishment of Non-Delivery Rates Effective August 1, 2003,* Docket No. ER02080614, Order dated April 20, 2004 at 53-54; 56.

120 Approximately 459 Mw, as indicated in the Audit Report at IX-1, exceeding the capacity of B. L. England (447 Mw).

Finally, we note that N.J.S.A. 48:3-50.c.(4) specifically requires that any proposed recovery of above-market power generation and supply costs, as well as other reasonably incurred costs associated with restructuring, be "subject to the public utility having taken and continuing to take all reasonably available steps to mitigate the magnitude of its above-market electric power generation and supply costs." Accordingly, the reporting requirements established herein are consistent with the Board's authority under EDECA.

D. SBC DEFERRED BALANCE

Only one adjustment, the disallowance of $1.417 million of the reserve for uncollectible accounts found excessive by the Auditors, has been recommended for the Company's deferred SBC balance. The adjustment was supported by the RPA and Staff, and accepted by the ALJ. In excepting to the ALJ's finding, the Company asserts that any such adjustment should await the processing of additional data for months subsequent to those examined by the Auditors. However, anticipated higher write-offs due to extreme summer weather in the year 2002, the asserted reason for the excess reserve, failed to materialize, as indicated by the Auditors at VI-6. Thus we fail to see why it is necessary to wait for data beyond the months of July and August 2002, which was available to the Auditors, in deciding this issue. Accordingly, we **HEREBY ACCEPT** the ALJ's finding on this issue, and **HEREBY DIRECT** the Company to reduce its underrecovered UA balance, and correspondingly increase its overrecovered SBC deferred balance, by $1.417 million.

The remaining SBC issues relate to the changes in the constituent elements of the SBC proposed by the Company, and the disposition of the net overrecovered SBC balance, as discussed below.

1. Universal Service Fund

The Company proposes to establish a new charge within the SBC for the recovery of USF costs incurred in the year 2002 and thereafter. The RPA argues that such a charge not be implemented at this time, but set in a separate proceeding, with the USF costs already incurred offset with a like amount of the overrecovered SBC balance. Staff supports the RPA's proposed offset, while the ALJ accepts the Company's proposal.

We find merit in the RPA's proposed offset, since it would avoid unnecessary billing complexity that would have the same net rate impact (refunding the overrecovered SBC balance only to have it separately offset by the new USF charge). For the same reason we believe the offset should be extended to the Company's share of the additional USF expenditures authorized by the Board's July 16, 2003 Order in Docket No. EX00020091, *I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999* ("July 16, 2003 Order"), as well as the Company's portion of the funding of the Lifeline Credit and Tenants Assistance Programs previously provided by the State, but now to be assumed by the State's gas and electric utilities, also as set forth in the July 16, 2003 Order.

In accordance with the funding formula set forth on page 5 of the July 16, 2003 Order, the Company's share of these costs is preliminarily estimated to be $9.0 million annually. Accordingly, the Board **HEREBY MODIFIES** the Initial Decision and **HEREBY ADOPTS** the RPA's recommendation to offset, with a like portion of the overrecovered SBC deferred balance, the $0.603 million of the Company's USF costs incurred and projected to be incurred and deferred during the Transition Period. An additional $9.0 million will be set aside to fund the Company's share of USF/Lifeline expenditures expected to be incurred annually in implementing the July 16, 2003 Order. Until fully offset by incurred costs, the $9.0 million balance will accrue interest at the Board-approved post-Transition Period rate, as will the difference between the balance and the USF/Lifeline costs actually incurred after the balance is fully offset. This difference will then be included as part of the USF/Lifeline rate recovery established when the Company's SBC rate is next changed, following the date the $9.0 million balance is fully offset.

The Company is additionally **HEREBY DIRECTED** to re-calculate the interest accrued on the deferred USF costs during the Transition Period to reflect the change in the interest calculation methodology ordered below.

2. Clean Energy Program

No party challenges the Clean Energy Program costs (CRA costs) the Company proposes to include in the SBC, which costs were authorized by the Board's March 9, 2001 Order in Docket Nos. EX99050347 et al, *supra*. This Order also required Atlantic's July 31, 2003 deferred DSM balance (assumed to be an overrecovery at the time) to be applied to the recovery of these costs. The RPA proposed delaying the implementation of a separate charge for the recovery of these costs at this time, and thus includes the projected July 31, 2003 DSM deferred balance with the other components of the deferred SBC balance, which it proposes to refund to customers over one year with interest. Citing the Audit Report, the RPA additionally recommends that in purchasing DSM services from an affiliate, the Company be directed to invoice such services in its name, or otherwise document that the services were in fact performed for the utility. Staff does not oppose the Company's CRA proposal. In rejecting the RPA's recommendation, the ALJ implicitly accepts the Company's proposal.

As set forth in N.J.S.A. 48:3-50.(10), one of the goals of EDECA was to "[e]nsure that improved energy efficiency and load management practices, implemented via marketplace mechanisms or State-sponsored programs, remain part of this State's strategy to meet the long-term energy needs of New Jersey consumers;" Accordingly, within four months of the enactment of EDECA and every four years thereafter N.J.S.A. 48:3-60.a.(3) required the Board to undertake a comprehensive resource analysis of energy programs in order to determine "the programs to be funded by the societal benefits charge, the level of cost recovery and performance incentives for old and new programs and whether the recovery of demand side management programs' costs currently approved by the board may be reduced or extended over a longer period of time. The board shall make these determinations taking into consideration existing market barriers and environmental benefits, with the objective of transforming markets, capturing lost opportunities, making energy services more affordable for low income customers and eliminating subsidies for programs that can be delivered in the marketplace without electric public utility and gas public utility customer funding;" The Board's initial CRA proceeding was instituted in June 1999, and culminated in the issuance of the March 9, 2001 Order *supra*.

The Board finds no reason for delaying the implementation of a charge for the recovery of these costs, which as the Company points out could grow in the future as new programs and/or increased spending levels are approved by the Board. Accordingly, the Board **HEREBY APPROVES** the inclusion of $11.435 million of annual Clean Energy Program/CRA costs in the SBC, offset by the overrecovered DSM deferred balance of $1.772 million projected to be incurred as of the end of the Transition Period.[121]

The Board shares the concerns expressed by the Auditors and the RPA with respect to the purchasing of DSM or other services from an affiliate. We also note that the Auditors raised this same concern in connection with certain customer care expenses included in MTC recoverable costs. (AUD-2 at V-10). Accordingly, in the event any services are purchased from any affiliate within the Pepco Holdings, Inc. corporate structure in the future, we **HEREBY DIRECT** the Company to: 1) invoice the services directly; and 2) document what the services were for and why the affiliate was chosen to supply them, as opposed to a non-affiliated company providing the same service. This documentation shall be retained and made available as needed for review in the proceedings in which the Company's unbundled rate charges are revised.

3. Uncollectible Accounts

The Board **HEREBY ACCEPTS** the Auditors' recommended $1.417 million adjustment to the reserve for uncollectible accounts, which was accepted by the RPA, Staff and the ALJ. The overrecovered SBC deferred balance shall accordingly be increased by this amount.

4. Consumer Education Program

The Company proposes to recover $3.914 million of CEP costs, the amount incurred and projected to be incurred during the Transition Period, over four years with interest at 5.44%, the rate applicable to the Company's deferred balances during the third year of the Transition Period. In its Initial Brief the RPA recommended that the Board disallow these costs on the basis that the Company had not demonstrated that they had been reasonably and prudently incurred. The RPA also contends that the Company's CEP program was largely ineffective in the years following the first year. The Company responds by asserting that no party challenged its claimed CEP costs during the hearings, and that the RPA now appears to be applying its own, as opposed to the Board's standard for the recovery of these costs. While reserving the right to review forthcoming CRPP reports and the Phase II Audit with respect to costs incurred from August 1, 2002 through March 31, 2003, and apart from the interest rate, Staff does not

121 The Board's determination of the Company's recoverable deferred balances is based on actual data through May 2003, as reported in the Company's June 23, 2003 deferred balance report filed with the Energy Division. Since the SBC deferral was not broken down into its components in that report, the projected DSM balance was supplied by the Company at Staff's request.

take issue with the Company's claim. Subject to the Board's confirmation that year 4 costs meet applicable standards, the ALJ finds that the Company's proposed CEP cost recovery should be adopted.

While clearly the results of energy choice have been disappointing to date, the Board believes that the dearth of solicitations from third party suppliers has been a much more significant reason for the lack of participation, particularly on the part of residential customers, than alleged shortcomings in the CEP program.[122] Moreover, as the Company points out, the reasonableness and prudence of its CEP costs were not challenged by any party during the hearings. Accordingly, the Board **HEREBY** **ACCEPTS** the ALJ's findings on this issue, and **HEREBY** **APPROVES** the CEP cost recovery requested by the Company.

With respect to the interest accrued on the CEP costs deferred during the Transition Period, the Board **HEREBY** **DIRECTS** the Company to recalculate the interest to reflect the change in the interest calculation methodology ordered below. Interest during the recovery period shall also be accrued net of tax, and in view of the fact that the proposed CEP cost recovery was never updated to reflect the interest rate applicable to the deferred balances in the fourth year of the Transition Period, the Company is **HEREBY** **DIRECTED** to employ a rate of 4.48% in accruing interest on the unamortized balance of these costs during the recovery period.

5. Nuclear Decommissioning Funding

The Board **HEREBY** **APPROVES** the Company's proposed elimination of decommissioning funding from the SBC, which was not opposed by any party, and recommended by the ALJ.

6. Disposition of SBC Overrecovery

As indicated above, ACE included the net overrecovered SBC balance as part of the deferred balances it proposes to recover over four years with interest at the seven-year treasury rate plus 60 basis points. The RPA asserts that, by including this balance with the BGS, NNC and MTC deferrals, the Company has not distinguished between the deferrals incurred in acquiring energy supply and the Company's other deferred costs. Moreover, certain costs associated with the BGS deferral may be eligible for securitization under the amended provisions of EDECA, while SBC costs are not. The RPA thus contends that it is appropriate to consider separate recovery or refund mechanisms for the SBC deferrals.

Based on actual data through January 2003, and after reflecting the Auditors' recommended reduction in the reserve for uncollectible accounts of $1.417 million (but no estimate of accrued interest), the RPA estimated that ACE's net overrecovered SBC balance would be $21.500 million as of the end of the Transition Period. The RPA proposed that this balance first be

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122 Citing steep increases in PJM capacity prices occurring early in 2001as the proximate cause (P-7 at 8), the Company averred that its customers began returning to BGS "in droves" (P-8 at 5) as third party suppliers cancelled their contracts, and by July 2001 "some 31,700 out of 33,000 (96%) customers who had been served by third-party suppliers were returned to the Company for BGS service." (*Id*. at 7).

applied to offset $0.603 million of USF costs incurred in the year 2002, thus obviating the need to establish a USF charge for the recovery of these costs effective August 1, 2003, and that the balance of the SBC overrecovery be refunded to customers as a one-time credit over one year with interest.

As noted above, on September 6, 2002, EDECA was amended to, among other things, establish a third category of securitizable stranded costs ("basic generation service transition costs"), defined as follows:

> "Basic generation service transition costs" means the amount by which the payments by an electric public utility for the procurement of power for basic generation service and related ancillary and administrative costs exceeds the net revenues from the basic generation service charge established by the board pursuant to section 9 of P.L.1999, c.23 (C.48:3-57) during the transition period, together with interest on the balance at the board-approved rate, that is reflected in a deferred balance account approved by the board in an order addressing the electric public utility's unbundled rates, stranded costs, and restructuring filings pursuant to P.L. 1999, c.23 (C.48:3-49 et al.). Basic generation service transition costs shall include, but are not limited to, costs of purchases from the spot market, bilateral contracts, contracts with non-utility generators, parting contracts with the purchaser of the electric public utility's divested generation assets, short-term advance purchases, and financial instruments such as hedging, forward contracts, and options. Basic generation service transition costs shall also include the payments by an electric public utility pursuant to a competitive procurement process for basic generation service supply during the transition period, and costs of any such process used to procure the basic generation service supply.
>
> [N.J.S.A. 48:3-51].

Clearly, SBC costs do not fall within this definition, and thus are not eligible for securitization. With respect to the other deferrals (the BGS, NNC and MTC deferrals), while they were incurred in providing energy supply, to the extent found prudent, the issue as to whether all or part of these balances are legally eligible for securitization, *i.e.*, whether they constitute basic generation service transition costs, is one of the issues the Board reserved to itself in the March 25, 2003 Secretary's Letter *supra*, and accordingly will be addressed upon the Company's filing of a petition seeking to securitize these costs.

The Company maintains that amortization of the SBC balance over four years appropriately reflects the same period over which the balance arose, and unlike the one-year credit proposed by the RPA, would avoid adding to a potential increase in the SBC charge next year, assuming additional renewable energy and load management programs are approved by the Board.

While supporting the RPA's proposed offsetting of year 2002 USF costs with a portion of the overrecovered SBC balance, Staff recommends that the ratemaking treatment to be accorded the remaining balance be considered in the Company's pending base rate case. The ALJ adopts the Company's position on this issue.

Having carefully considered the positions of the parties and the ALJ's findings, the Board believes the RPA's proposal, modified to reflect the offsets noted below, is preferable from both the standpoint of moderating the rate increase that will result from this proceeding and in keeping with the annual revisions and true-up methodology that will be employed with the SBC going forward. Moreover, we find it desirable and reasonable to remit the amount collected for decommissioning costs that are not going to be incurred, the primary source of the SBC overrecovery, to ratepayers at the earliest possible opportunity. Accordingly, we **HEREBY REJECT** the ALJ's findings on this issue, and **HEREBY DIRECT** the Company, after: 1) increasing the overrecovered SBC balance to reflect the Auditors' UA adjustment of $1.417 million; 2) offsetting USF costs of $9.603 million with a like portion of the overrecovered SBC balance; and 3) applying an additional $1.772 million of the overrecovered SBC balance to offset initial annual Clean Energy Program/CRA cost recovery, to remit the remaining balance to customers over one year. Consistent with our approval of levelized recovery of the Company's CEP costs net of tax with interest, the refund of the remaining SBC balance shall also be remitted on a levelized basis, net of tax, with interest at the rate of 4.48%, the rate applicable to deferrals during the fourth year of the transition period.

Based on actual data through May 2003, the Company's overrecovered SBC balance is projected to be $22.553 million at the end of the Transition Period, without interest.[123] After adding the UA disallowance and deducting the offsets just noted, and adding estimated interest of $1.2 million accrued during the Transition Period**,** the balance to be remitted to ratepayers is $13.795 million.[124] Accordingly, subject to a true-up to reflect actual data through July 31, 2003, the results of the Phase II Audit, and a recalculation of accrued interest to reflect the change in the interest calculation methodology ordered below and the effect of the UA disallowance, the Company is **HEREBY DIRECTED** to reduce its SBC by $13.8 million on an annual basis effective August 1, 2003.

[123] Determined by adding the SBC deferrals forecast for June and July from Schedule HACR-10 attached to P-13 to the May SBC balance shown in the June 23, 2003 deferred balance report filed with the Board's Energy Division.

[124] In the Summary Order the UA disallowance of $1.417 million recommended by the Auditors was erroneously subtracted from, rather than added to, the overrecovered SBC balance in determining the portion of the SBC balance to be remitted to ratepayers. The estimated $(1.2) million of accrued interest on the SBC balance was also understated, as noted below, and should have been approximately $(2.3) million ($(4.0) million x (1-0.4085)).

E. OTHER ISSUES

1. Interim Deferral Recovery

The ALJ made no findings on issues related to the securitization and/or amortization of the deferred balances in light of the Board's March 25, 2003 letter recalling these issues to the Board. However, the Board's letter stated that it would consider proposals for the interim recovery of the deferred balances pending its final decision on the ultimate recovery mechanism to be accorded the balances.

Pending the planned filing of a securitization petition, ACE proposed a four-year amortization of all of its deferred balances in the aggregate, with carrying costs accrued at the rate on seven-year treasury notes plus 60 basis points, revised annually. Under the Company's proposal, and based on its aggregate deferred balance as filed, the payment for deferral recovery would be approximately $49.2 million per year, assuming an interest rate of 5.44%. As shown in Exhibit S-8, if the balance were to be recovered net of tax, the annual payment would be reduced by about $2 million, or to $47.2 million per year. For illustrative purposes only, the RPA proposed recovery of the same aggregate balance over 10 years, net of tax, with the interest rate fixed as of the beginning of the period. Based on an assumed rate of 4.31%, the RPA calculated deferral recovery of $21.5 million per year. Staff proposed interim recovery of the Company's BGS, NNC and MTC deferred balances over 10 years, and in view of the short period in which the recovery was anticipated to be in effect, proposed using the yield on one-year constant maturity treasury notes plus 30 basis points as the interest rate.

After carefully reviewing the positions of the parties the Board agrees with the recommendation of Staff and the RPA with respect to net of tax recovery and the ten-year term, as opposed to the recovery of the gross balance over four years as proposed by the Company. The Board finds the proposals of Staff and the RPA to be desirable from both the perspective of reducing the rate impact on customers (including the impact of the BGS increase noted below) and the likelihood that the recovery period ultimately approved by the Board for either securitization or amortization will be closer to ten years than to four.

With respect to carrying costs, the Board's only concern at this time is the establishment of a transitional financing mechanism of very limited duration, with the intent of compensating the Company for its interest costs actually incurred in financing the deferred balances during a period of record low interest rates, pending securitization or other permanent financing. Accordingly, for purposes of interim recovery pending our decision on the securitization petition the Company is expected to file, the Board **HEREBY FINDS** a ten-year amortization period to be appropriate, and that carrying costs on the unamortized balance during the period of interim recovery shall be accrued at a rate equal to the yield on constant maturity one-year treasury notes plus 30 basis points, or 1.3%, based on the yield for the week ending June 27, 2003, as reported in the Federal Reserve Statistical Release dated July 1, 2003. As applied to the combined BGS, NNC and MTC deferred balance of $125.0 million, which the Board finds recoverable at this time, as discussed below, and subject to a true-up to reflect actual data through July 31, 2003, the results of the Board-ordered Phase II Audit of the Company's deferred balances and a recalculation of accrued interest to reflect these adjustments and the disallowances and interest calculation methodology ordered herein, the Board **HEREBY APPROVES** interim deferral recovery of $13.035 million per year before application of the 6% New Jersey Sales and Use Tax.

2. Interest Calculation

As discussed above, for each year of the Transition Period, the Final Restructuring Order authorized the accrual of interest on the Company's deferred balances at the rate on constant maturity seven-year treasury notes, as reported in the Federal Reserve Statistical Release closest to August 1st of each year, plus 60 basis points. RPA witness Crane accordingly used this rate in re-computing interest on the Company's deferred balances after reflecting her recommended disallowances. However, she applied the rate to the so-called "net of tax" deferred balances (the balances reduced by the related deferred income taxes), reflecting the fact that when the deferred costs were incurred they were deductible for income tax purposes. She also averred that it was her understanding that the Board had expressly stated that deferrals should be calculated on a net of tax basis.[125] In addition, she calculated interest on each of the Company's deferred balances (the BGS, NNC, MTC and SBC balances) separately[126] (RA-2 at 25-26; Schedules ACC-2A (BGS); ACC-7 (NNC); ACC-8A (MTC) and ACC-10 (SBC)), while the Company calculated interest on the net balance of all components in the aggregate. The Company also accrued interest on a "gross" basis (on the aggregate balance unreduced by the related deferred income taxes). Similarly, RPA witness Rothschild calculated his illustrative deferral recovery net of tax, noting that the tax benefit realized from the deductibility of the deferred costs during the Transition Period reduced the deferred costs that needed to be financed by the amount of the tax reduction (the deferred costs multiplied by 40.85%, the composite federal and State income tax rate). (RA-18 at 15-16).

Staff also recommends that interest be calculated on the deferred balances net of tax during both the Transition Period and when the balances are recovered, asserting that not only is net of tax treatment sound regulatory practice, it is in accordance with the Board's Orders approving this treatment when tax benefits effectively reduce financing costs, as evidenced most recently by the Board's October 16, 2002 Order in Docket Nos. EO97070464, EO97070465 and EO97070466 cited *supra*. Moreover, Staff asserts that all securitizations of stranded costs approved by the Board to date have been structured on a net of tax basis, and when approved for accrual on the unamortized balance of PSE&G's RAC costs, carrying costs were also to be

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125 Citing the Board's Order dated July 22, 2002 in Docket Nos. EO97070464, EO97070465 and EO97070466, *I/M/O Rockland Electric Company's Rate Unbundling, Stranded Cost and Restructuring Filings*, at 69, paragraphs 28-29.

126 The Company mistakenly asserted that witness Crane re-computed interest net of tax on only the BGS deferred balance. (CIB at 44, footnote 11) . After reflecting all of the RPA's recommended disallowances and actual data through October 2002, the RPA's recommended interest was $0.914 million, as compared to the Company's claim of $8.887 million based on no disallowances and actual data through December 2002. (Schedule ACC-1 attached to RA-2; Schedule HACR-15 attached to P-13).

determined net of tax. Going forward, on post-Transition Period deferrals, Staff additionally proposes changing the interest rate from the seven-year treasury rate plus 60 basis points approved by the Board for application to deferrals during the Transition Period to the rate actually incurred on the Company's short-term debt (debt maturing in less than one year), or in the event no short-term debt is outstanding, the rate available on equivalent short-term temporary cash investments. (SIB at 41, Appendix SIB-1; SRB at 5-7, Appendixes SRB-1 and SRB-2).

In opposing net of tax interest accruals on its deferred balances during the Transition Period, the Company cites the interest calculation methodology used with its former LEAC, as set forth in N.J.A.C. 14:3-13, and asserts that interest on over and underrecovered LEAC balances had always (as far back as 1978) been calculated on the gross balance. In further support of its continued use of the LEAC interest calculation methodology the Company cites the Final Restructuring Order, which in paragraph 43 on page 96[127] states: "In setting the annual level of charges for BGS during the Transition Period, for any MTC that continues beyond the Transition Period, and for the SBC, NNC and the TBC [Transition Bond Charge], the Company will utilize a methodology similar to that currently used for setting its Energy Adjustment clause charges." The Company argues that in defining the rate to be used in accruing interest during the Transition Period, the Final Restructuring Order states (at 82) that the rate was to be applied to "underrecovered balances," not net of tax balances, and that nowhere in the Final Restructuring Order did the Board indicate that interest on the deferred balances should be calculated net of tax. If the Board had wanted to change its policy on the interest calculation methodology, the Company avers, it would have said so, and to change the methodology now and apply it to interest accruals made during the Transition Period would in its view constitute retroactive rate making. (P-13 at 5-6).

NJLEUC took no position on this issue. In rejecting Staff's and the RPA's proposed calculation of interest on a net of tax basis, the ALJ mistakenly assumed that it had been proposed with respect to the LEAC interest issue. (I.D. at 17; 19).

In considering the net of tax issue and Staff's interest proposals, the Board believes it is useful to first review the method prescribed for accruing interest on adjustment clause over and underrecoveries by N.J.A.C. 14:3-13.3 and 13.4, as well as its intended purpose. As set forth in 13.3, the utility's last allowed overall rate of return is to be employed as the interest rate (in this instance, 10.52%, as indicated in Schedule HAC-2 attached to P-11). A cumulative over or underrecovered balance is determined by adding the current month's underrecovery to, or subtracting the current month's overrecovery from, the balance at the end of the previous month for each month of the clause period. Monthly interest is then calculated by applying the interest rate to the beginning and end average of the cumulative over or underrecovered balance each month, which, as the Company points out, is not stated as being net of tax. The interest is also accumulated without compounding, as illustrated in Schedule HAC-2. If at the end of the clause period the accumulated interest is negative (a credit balance, reflecting net overrecoveries), the

[127] Page 95 in some printed versions of the Final Restructuring Order.

balance is remitted to ratepayers as part of the clause true-up. If positive, the interest is "zeroed out." Thus interest is "one way," with the Company precluded from recovering interest on net underrecoveries, while paying interest on net overrecoveries.

While not stated in the regulation, the purpose of both using a relatively high interest rate (the overall rate of return, which includes an equity component) as well as one way interest recovery, was to provide an incentive to the utility to use conservative forecasts in seeking revisions in its LEAC, which was determined on a forecast basis.[128] The forecasts, in turn, involved a great many variables: fuel prices, generating unit availability, purchased power costs, the level of kwh sales, and the like.

Looking first at the net of tax issue, while the Final Restructuring Order does not state that deferred taxes should (or should not) be deducted from the Company's deferred balances in accruing interest, the lack of specificity on this implementation detail does not preclude review of the issue by the Board at the time these deferred balances are being reviewed and trued up. The Restructuring Orders made it clear that the deferred balances would be subject to review and true-up by the Board at the end of the Transition Period, and therefore, the Company's suggestion that such a review and true-up constitutes retroactive ratemaking has no merit here.[129] The Board agrees with Staff's contention that the post-Transition Period review of the utility deferrals required by the Board's Restructuring Orders does, in fact, permit such an adjustment for the reasons noted above, and in view of the lack of uniformity of the interest calculation among the four utilities.

With respect to the reference to the Energy Adjustment clause in the Final Restructuring Order cited by the Company, we agree with Staff that this language refers only to the rate recovery mechanism, *i.e.*, the use of an adjustment clause as the means of setting the Company's post-transition BGS charges, the MTC (if continued), SBC, NNC and TBC, and is silent both with respect to the interest rate to be used, which is defined elsewhere in the Order, and the balance to which it is to be applied.

We would also add that if, except for the change in the rate, the Board intended for the other provisions of N.J.A.C. 14:3-13 to apply to the calculation of interest on deferrals during the Transition Period, and if each component of the Company's unbundled rates (its BGS, NNC, MTC and SBC charges) were to be viewed as a separate "adjustment clause," the Company would be precluded from recovering interest on its underrecovered balances (the BGS and MTC

[128] As set forth in 13.2, the LEAC was to be determined on an estimated basis.

[129] The retroactivity issue also came up in PSE&G's deferred balances proceeding in response to the RPA's and Staff's proposed accruing of interest on PSE&G's deferred balances net of tax. While arguing that this change would upset interrelated provisions of the 1999 Stipulation of Settlement approved by the Board in PSE&G's restructuring proceedings (Docket Nos. EO97070461, 462 and 463), in the opinion of PSE&G's witness on the issue, the net of tax adjustment would not constitute retroactive ratemaking: "I don't think I have argued that the proposed adjustment here would violate statutory definitions of retroactive rate-making." (March 3, 2003 hearing in Docket No. ER02080604 *supra*, 10T at 1668).

balances) while being obligated to remit interest to ratepayers on its overrecovered balances (the NNC and SBC balances). Clearly, that was not our intent.

With respect to Staff's proposed change in the interest rate applicable to post-Transition Period deferrals (both under and overrecoveries), we note that with the advent and assumed continuation of the statewide auctions held annually for obtaining BGS supply for the state's electric utilities, there is no longer a need to retain an "incentive" feature in the accrual of interest on BGS under and overrecoveries, since the amount to be paid for BGS supply will be known in advance, and accordingly, the only BGS deferrals that will occur will be those arising from temporary timing differences between payments made to suppliers and the related revenue received from customers. Additionally, given the fact that, other than its distribution charges, the Company's unbundled rate components will be adjusted annually, we find that Staff's proposed use of the short-term debt rate and its applicability to the over or underrecovered deferred balances, reduced by the deferred income taxes associated with both the deferred costs and deferred interest, will much more closely approximate the true cost of carrying the deferred balances than either the seven-year treasury rate plus 60 basis points employed during the Transition Period, or the overall rate of return employed with the previously-effective LEAC applied to the gross balance (the balance unreduced by related deferred income taxes). Accordingly, we **HEREBY REJECT** the ALJ's finding on the net of tax issue, and **HEREBY DIRECT** the Company to recalculate the interest accrued on its post August 1, 1999 deferred balances on a net of tax basis, *i.e.*, to deduct deferred income taxes associated with both the deferred costs and the deferred interest from the balance on which the interest is accrued. This directive shall also apply to the interest accrued on USF and CEP costs deferred during the Transition Period. We additionally **HEREBY APPROVE** the use of the Company's monthly actual cost of short-term debt (debt maturing in less than one year) as the interest rate to be applied to post-Transition Period (post August 1, 2003) BGS, NNC, MTC and SBC deferrals, or if no short-term debt is outstanding, the rate on equivalent temporary cash investments shall be so used. Finally, in the interest of standardizing the interest calculation among the electric utilities, in addition to accruing interest monthly on the beginning and end average net of tax balance of deferred costs, the Company shall be authorized to compound interest annually.[130]

F. RATE DESIGN

With regard to Rate Design, the Board **HEREBY ADOPTS** the Initial Decision's recommendation to approve ACE's request to utilize a flat energy charge to recover both MTC and NNC costs, with an adjustment for loss factors as proposed by NJLEUC, supported by Staff and accepted by the Company. In making this decision, the Board considered both the

[130] As illustrated in Exhibit 2 attached to the Board's Final Decision and Order in RECO's deferred balance and base rate case proceedings, Docket Nos. ER02080614 and ER02100724, *I/M/O the Verified Petition of Rockland Electric Company for the Recovery of its Deferred Balances and the Establishment of Non-Delivery Rates Effective August 1, 2003*, and *I/M/O the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, its Tariff for Electric Service, its Depreciation Rates, and for Other Relief,* dated April 20, 2004.

evidence in this case and the nature of the costs recovered through these charges. The Board recognizes that costs associated with generating plants, which are recovered by the NNC (and at least for now by the MTC) have historically been recovered from customers through energy charges. Moreover, the Board recognizes that each time there is a step down to a lower voltage, the percentage of line loss increases. Historically customer class rates have reflected different line loss factors, depending upon such voltage levels. For the same reasons, the Board **FURTHER ADOPTS** the ALJ's recommendation that the deferred balances be recovered by the application of a flat energy charge to all kwh sales uniformly across all customer rate schedules, which via its inclusion in the MTC will also be adjusted to reflect line losses.

G. SUMMARY OF BOARD FINDINGS

(a) Deferred BGS/NNC/MTC Balances

1. As described more fully herein and summarized in Exhibit 2 attached hereto, based on a combined BGS, NNC and MTC deferred balance of $195.0 million projected to be incurred by the Company as of July 31, 2003, including estimated interest of $9.9 million,[131] and after deducting: 1) aggregate BGS and NNC disallowances of $35.5 million; 2) misclassified regulatory asset amortizations of $2.6 million; 3) estimated disallowed interest of $6.5 million; and 4) BGS administrative costs, restructuring/ transition and TPS billing costs aggregating $22.9 million, and legal costs incurred in the Logan dispute of $2.5 million, all of which are to continue to be deferred and litigated in the Company's pending base rate case, the Company is **HEREBY AUTHORIZED** to recover an aggregate BGS, NNC and MTC deferred balance of $125.0 million.

2. This balance shall be trued-up to reflect: 1) actual data through July 31, 2003; 2) the results of the Board-ordered Phase II Audit of the Company's deferred balances; and 3) a recalculation of accrued interest to reflect these adjustments as well as the disallowances set forth above, and the change in the interest calculation methodology the Company is directed to implement below.

3. For purposes of interim deferral recovery pending the Board's decision on the securitization petition the Company is expected to file, the aggregate BGS, NNC and MTC deferred balance set forth in paragraph 1 above shall be recovered at the rate of

131 Based on actual data through May 2003, as reported in the Company's deferred balances report filed with the Board's Energy Division by letter dated June 23, 2003, and forecast data for the months of June and July 2003 from Schedule HACR-10 attached to P-13. The interest disallowance was determined by subtracting $3.4 million of adjusted interest calculated in Appendix SRB-2 attached to Staff's Reply Brief from the estimated interest of $9.9 million noted above. A re-calculation of the estimated interest indicates it should have been $12.7 million for the aggregate BGS, NNC and MTC balance before the net of tax and other adjustments, and $(4.0) million for the SBC balance, or $8.7 million net for all deferred balances in the aggregate. A corrected (final) interest determination will be made as part of the true-up required by paragraph 2 above. While a substantial interest disallowance would also accompany the Advocate's recommended disallowances, how much it might be was not estimated in Exhibit 2 attached.

$13.035 million per year before application of the 6% New Jersey Sales and Use Tax. This recovery is based on a 10-year amortization of the balance net of tax, and an interest rate equal to the yield on one-year constant maturity treasury notes as of the week ending June 27, 2003, as reported in the Federal Reserve Statistical Release dated July 1, 2003, plus 30 basis points, or 1.3%.

4. The Company shall file quarterly reports on the status of its NUG cost mitigation efforts and monthly reports on the use of its NUG capacity and generation, as provided herein. The first quarterly report will be due within 90 days of the date of this Order.

5. Effective on the date the Company's non-distribution unbundled rates are next changed, the NNC and MTC shall be replaced by the NGC ("non-utility generation charge"), which charge shall continue to recover the above-market component of payments made under PPAs with non-utility generators (the PPA payments less the revenue received from the sale of the NUG energy and capacity), as well as the operation and maintenance expenses of B. L. England and the revenue requirement of Keystone and Conemaugh, net of the revenue received from the sale of the capacity of and generation from these units, as well as such other costs as have been approved by the Board for inclusion in the MTC, as set forth in the Final Restructuring Order, and the interim deferral recovery approved herein, until further Order of the Board, *i.e.*, pending the Board's further consideration of the ratemaking treatment to be accorded these costs in Phase II of the Company's pending base rate case.

6. The "carry over" issues from this as well as the B. L. England proceeding (Docket Nos. EO03020091 *et al*), including the capacity pricing and other issues associated with Deepwater and the transferred CTs, are to be addressed in the Company's pending base rate case (Docket No. ER03020110), as set forth in the Board's Orders in Docket Nos. ER02080510 *et al* dated January 26, 2004 and December 12, 2003 (at 3-5). To be added to these issues are the merchant support costs and costs incurred in issuing RFPs I and II, as described herein.

7. The recommended verification and reconciliation of the cost of energy and capacity recorded by the Company with that based on PJM market prices, as recommended by the Auditors (AUD-2 at VIII-56), shall continue to be pursued in the Phase II Audit.

8. The Board **HEREBY APPROVES**, effective August 1, 2003, the Company's requested $40.1 million annual increase in the NNC, exclusive of the 6% New Jersey Sales and Use Tax, and in view of the continued retention of B. L. England, **HEREBY DIRECTS** the Company to maintain the component of its MTC charge for the recovery of costs other than its BGS, NNC and MTC deferred balances at its current level.[132]

[132] On the assumption that the fossil units would be divested by March 2003, the Company had proposed reducing this component of the MTC by $10.8 million annually. (P-14, Schedule JFJ-7).

(b) SBC Deferred Balance/Charges

1. As described more fully herein, after reflecting the UA disallowance of $1.4 million and estimated accrued interest of $(1.2) million,[133] of the SBC balance of $25.2 million projected to be overrecovered as of July 31, 2003: 1) $0.6 million shall be used to offset deferred USF costs incurred by the Company in the year 2002 and an additional $9.0 million to offset current USF costs, as approved by the Board's Order dated July 16, 2003 in Docket No. EX00020091; 2) the portion of the balance associated with DSM costs (an estimated $1.8 million overrecovery) shall be used to offset the Clean Energy Program/CRA costs authorized for inclusion in the SBC below; and 3) the remaining balance, estimated to be $13.8 million, shall be used to reduce the Company's SBC charges on an annual basis with interest as provided herein, effective August 1, 2003.

2. The overrecovered SBC balance shall be trued up to reflect actual data through July 31, 2003, the results of the Phase II Audit, and a recalculation of accrued interest to reflect these adjustments, the UA disallowance, and the change in the interest calculation methodology ordered herein.

3. The Company is **HEREBY AUTHORIZED** to include Clean Energy Program/CRA costs of $11.4 million per year in the SBC, effective August 1, 2003.

4. The Board **HEREBY APPROVES**, effective August 1, 2003, the Company's requested net decrease of $1.8 million in its SBC charges, exclusive of the 6% New Jersey Sales and Use Tax (a reduction of $7.3 million due to the elimination of decommissioning funding, an increase of $1.0 million due to the addition of CEP cost recovery, and an increase of $4.5 million due to the change in the DSM/CRA component).[134] The difference in allowed recovery attributable to the change in the interest rate and calculation methodology ordered herein shall be trued up when the SBC is next revised.

(c) Interest Calculation

1. The Board **HEREBY DIRECTS** the Company to recalculate its interest accruals during the Transition Period to reflect: 1) the deduction of deferred income taxes associated with the deferred costs and deferred interest from the balance of deferred costs on which

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133 Based on actual data through May 2003, as reported in the deferred balances report filed with the Board's Energy Division on June 23, 2003 and forecast data for the months of June and July from Schedule HACR-10 attached to P-13. As indicated above, the interest allocated to the SBC deferred balance before adjustments (the interest that would have been determined by the Company) should have been approximately $(4.0) million rather than $(1.2) million.

134 All as shown in Schedule JFJ-7 attached to P-14. The $4.6 million noted on page 5 of the Summary Order as being the combined increase sought for Clean Energy and Consumer Education Program costs was in error, and should have been $5.5 million.

interest is accrued; and 2) annual compounding.[135] For the purpose of making the true-ups required above, interest shall be calculated separately for the aggregate BGS, NNC and MTC deferred balance and the SBC balance.

2. The above directive shall also apply to the interest accrued on USF and CEP costs deferred during the Transition Period. Additionally, interest on the unamortized balance of CEP costs and the portion of the overrecovered SBC balance that is to be refunded to customers shall be accrued net of tax at the rate of 4.48% during the recovery period.

3. For post-Transition Period deferrals, *i.e.*, effective August 1, 2003, the method of calculating interest on the Company's BGS, NNC/MTC/NGC and SBC deferrals shall be as described in paragraph 1 above, but the interest rate shall be reduced from the yield on seven-year constant maturity treasury notes plus 60 basis points to the average rate on the Company's short-term debt outstanding (debt due in one year or less), or in the event that no short-term debt is outstanding, to the rate on equivalent temporary cash investments, determined monthly.

(d) Deferred Accounting

1. The Board **HEREBY APPROVES** continued use of deferred accounting for under and overrecoveries of costs recoverable by the NNC/MTC/NGC and SBC, as well as for under and overrecoveries of costs incurred in supplying BGS, all of which such under or overrecoveries shall be recorded as regulatory assets and liabilities on the balance sheet.

H. EFFECT OF ALL RATE CHANGES

The rate changes approved herein result in a net increase in the Company's NNC, MTC and SBC charges of approximately $37.5 million, or an average rate increase to all customer classes of approximately 4.4%. In addition to these rate changes, the Company will implement an increase in its BGS charges effective August 1, 2003 to reflect the results of the statewide auction previously approved by the Board by Order dated February 6, 2003 in Docket No. EX01110754, *I/M/O the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. – Basic Generation Service Auction Results*. The Company estimates that the average increase for all customers taking fixed price BGS will be about 3.4%, which when added to the increase approved herein yields a total increase of approximately 7.8%. For the average residential customer using 750 kwh per

[135] The Company currently calculates interest monthly on the beginning and end average balance, and this methodology is to be retained.

month, the average annual increase will be approximately 6% (from $85.77 per month to $90.93 per month).

DATED: ***July 8, 2004***

BOARD OF PUBLIC UTILITIES
BY:

SIGNED

JEANNE M. FOX
PRESIDENT

SIGNED

FREDERICK F. BUTLER
COMMISSIONER

SIGNED

CAROL J. MURPHY
COMMISSIONER

SIGNED

CONNIE O. HUGHES
COMMISSIONER

SIGNED

JACK ALTER
COMMISSIONER

ATTEST: ***SIGNED***
KRISTI IZZO
SECRETARY

EXHIBIT 1

ATLANTIC CITY ELECTRIC COMPANY
Docket No. ER02080510

BGS Supply by Sources
Three Years Ended July 31, 2002

		% of	Energy		Capacity		Total	
	Gwh	Total	$Millions	$/Mwh	$Millions	$/Mwh	$Millions	$/Mwh
TBD Generation	10,123	38.5%	$160	15.79	$ 451	44.58	$ 611	60.37
NUGs	8,994	34.2	269	29.91	454	50.48	723	80.39
TPP & Bilateral Contracts	3,956	15.1	200	50.44	116	29.32	316	79.76
PJM (Net)	3,212	12.2	181	56.36	22	6.93	203	63.29
Total	26,285	100.0%	$810	30.80	$1,043	39.71	$1,853	70.50

Source: Schedule JAE-1 (Revised), P-8. $/Mwh based on unrounded data.

EXHIBIT 2

ATLANTIC CITY ELECTRIC COMPANY

Docket No. ER02080510

Projected BGS, MTC and NNC Deferred Balances
and Recommended Disallowances
($ Millions)

		ACE	Audit	RPA	Staff	ALJ
Projected balances at end of Transition Period (July 31, 2003) **						
BGS	$ 62.4					
MTC	130.7					
NNC	(8.0)					
Interest	9.9					
Total	$195.0	$195.0	$195.0	$195.0	$195.0	$195.0
BGS Disallowances						
Third party purchases, July/Aug. 2001				(25.5)	(25.5)	
Excess capacity purchases				(3.4)	(3.4)	
LEAC interest				(2.0)		
BGS administrative costs				(3.5)	(3.5)*	
Too little capacity purchased, RFP III			(6.1)	(6.1)	(6.1)	(6.1)
MTC Disallowances						
Restructuring/transition costs		(0.2)		(15.3)	(15.3)*	(0.2)
Consolidated TPS billing costs				(4.1)	(4.1)*	
Cash working capital, TBD units				(3.8)		
Post-August 1, 2002 above-market cost of TBD fossil units				(29.6)		
Misclassified regulatory asset amort.		(2.6)	(2.6)	(2.6)	(2.6)	(2.6)
NNC Disallowances						
Logan heat rate dispute				(2.5)	(2.5)*	
Interest reduction, Pedricktown buyout			(0.5)	(0.5)	(0.5)	(0.5)
Disallowed interest					(6.5)	
Total disallowances/misclassifications		$ (2.8)	$ (9.2)	$(98.9)	$(44.6)	$ (9.4)
Continue to litigate in base rate case (* items)					(25.4)	
Balance recommended for interim recovery		$192.2	$185.8	$ 96.1	$125.0	$185.6

** Excludes SBC balance. As calculated by Staff based on actual balances as of May 31, 2003, and projections of June and July 2003 from Schedule HACR-10 attached to P-13. See note on page 130 of the text for derivation of projected deferred and disallowed interest.

ATLANTIC CITY ELECTRIC COMPANY
Docket No. ER02080510

BGS Supply Cost Comparison
Atlantic City Electric, JCP&L and RECO
Three Years Ended July 31, 2002
(Revised Appendix SIB-3, Staff's Initial Brief)

($ Millions)

	All Sources of Supply			Discretionary Component		
	Gwh	Cost	$/Mwh	Gwh	Cost	$/Mwh
Atlantic Electric	26,285	$1,853	70.50	6,597	$ 501	75.90
JCP&L	61,218	3,736	61.02	42,969	2,233	51.97
RECO	4,724	268	56.73	4,532	251	55.38

Notes:

Both Atlantic and JCP&L retained a portion of their generating units during all or some portion of the three-year period. Pre-divestiture, the output of these units was devoted to BGS supply, and the revenue requirement of the units was included as part of each company's recoverable costs.

All three companies devoted their NUG purchases to BGS supply, priced at differing definitions of market value, with the above-market component recovered by the NNC (Atlantic), by the MTC (JCP&L), and by the ECA (RECO).

The "discretionary component" is defined to be the portion of BGS supply not obtained from to-be-divested generating units, pre-Transition Period NUG power purchase agreements, and with the exception of parting contracts associated with the divestiture of generating units, PPAs entered into with other utilities prior to August 1, 1999. Thus the discretionary component is the portion of BGS supply that was obtained from parting contracts, the spot market (PJM or the NYISO), post-August 1, 1999 third party and bilateral power purchases, RFPs, or some combination of these at the option of the utility.

PSE&G is not included, since all of its BGS supply was contractually supplied by its unregulated affiliate, PSEG Power LLC during the first three years of the transition period and priced at the energy and capacity component of PSE&G's shopping credit. Thus unlike the other three utilities, PSE&G was not faced with the responsibility of obtaining BGS supply during the period.

Sources:

Atlantic: Schedule JAE-1 (Revised) attached to the Rebuttal Testimony of company witness Jerry A. Elliott (Exhibit P-8), with the pre-Transition Period PECO purchase (571 Gwh, $18.1 million) deducted from "Other Contracts" in determining the cost of discretionary purchases ("PJM Markets" plus "Other Contracts" purchases).

JCP&L: Schedule SDM-1A ("12+0" Update) attached to the Direct Testimony of company witness Susan D. Marano (Exhibit JC-13) and Exhibits S-32 and S-36 submitted in JCP&L's deferred balances proceeding (BPU Docket No. ER02080506; OAL Docket No. PUC 7894-02). Categories included in determining the cost of discretionary purchases are: Bilateral Purchases ($1,125 million, 18,735 Gwh from S-32); PJM Purchases ($438 million from SDM-1A, 11,321 Gwh supplied by the company by e-mail); TPPAs ($558 million from SDM-1A, 12,913 Gwh from S-36); Ancillary Services ($98 million from SDM-1A); and Financial Instruments ($14 million from SDM-1A). Cost of "All Sources of Supply" additionally includes the cost of retained generation (including return on and of Oyster Creek investment) and the cost of purchases under pre-Transition Period NUG and utility PPAs, less the revenue received from Sales for Resale, all from SDM-1A, with the energy requirement supplied by the company in response to S-JMTC-5.

RECO: Schedules FPM-2 and 3 included in Exhibit RECO-2, and Schedule JAH-10 attached to the Direct Testimony of company witness Joseph Holtman (Exhibit RECO-4) submitted in RECO's deferred balances proceeding (BPU Docket No. ER02080614; OAL Docket No. PUCOT 07892-02). The cost of "All Sources of Supply" was determined by adding the above-market cost of NUG purchases (ECA Costs) from FPM-3 ($7.1 million for the three years ended July 31, 2002) to total BGS costs shown on page 1 of Schedule FPM-2 for the same period ($260.7 million). The "Discretionary Component" was determined by deducting NUG costs of $16.3 million, based on 192 Gwh purchased and priced at the unit cost ($85.01 per Mwh) derivable from JAH-10. The Gwh of NUG purchases as well as the total Gwh purchased were supplied by the company by e-mail.

EXHIBIT 4

ATLANTIC CITY ELECTRIC COMPANY
Docket No. ER02080510

Cost Comparison, RFP IV Capacity Purchases
vs. All Other Capacity Purchases
June 2001 – July 2002

	Days	RFP IV Purchases		Other Purchases		RFP IV Cost in Excess of Other Purch.		
	In Month	Mw	$/Mw-Day	Mw	$/Mw-Day	$/Mw-Day	$Millions	%
June 01	30	800	$177.50	525	$161.55	$ 15.95	$ 0.4	10%
July	31	"	"	539	162.18	15.32	0.4	9
August	31	"	"	551	161.58	15.92	0.4	10
September	30	"	"	551	161.58	15.92	0.4	10
October	31	"	"	525	161.55	15.95	0.4	10
November	30	"	"	529	160.40	17.10	0.4	10
December	31	"	"	529	160.40	17.10	0.4	10
January 02	31	"	"	550	63.41	114.09	2.8	180
February	28	"	"	550	63.41	114.09	2.6	180
March	31	"	"	807	49.59	127.91	3.2	258
April	30	"	"	707	54.27	123.23	3.0	227
May	31	"	"	737	52.87	124.63	3.1	236
June	30	"	137.50	558	83.29	54.21	1.3	65
July	31	"	137.50	658	97.74	39.76	1.0	41
Totals/Avg.	426	800	$171.77	595	$108.72	$ 63.05	$19.8	58%

Source: Schedule 1(e), Schedule JAE-1, P-8.

EXHIBIT 5

ATLANTIC CITY ELECTRIC COMPANY
Docket No. ER02080510

NUG Purchased Power Costs
and Revenue Requirement of TBD Generation
July and August 2001

	Cap. .(Mw)	Gwh Gen or Purch.	% of Total	Cap. Factor	$Millions	$/Mwh *
NUGs	459	627	56.3%	91.9%	$44.3	$70.66
B. L. England	447	343	30.8	51.5	22.5	65.75
Keystone & Conemaugh	108	144	12.9	89.7	3.1	21.29
Return on Nuclear Investment	-	-	-	-	10.3	- .
Total	1,014	1,114	100.0%	73.9%	$80.2	$72.00

* based on unrounded data.

Source: NUGs – Schedule 1(b), Schedule JAE-1 (Revised), P-8

B. L. England, Keystone & Conemaugh – Staff Exhibit S-2

Return on Nuclear Investment – by difference (total revenue requirement of TBD generation from Schedule 1(a), Schedule JAE-1 (Revised), P-8, less above components)